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ENHANCED COAL TECHNOLOGY

HEARING

BEFORE THE

SUBCOMMITTEE ON
ENERGY AND MINERAL RESOURCES

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

NINETY-EIGHTH CONGRESS

FIRST SESSION

ON

ENHANCED COAL TECHNOLOGY: COAL'S MARKET FOR THE EIGHTIES

AUGUST 9, 1983

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ENHANCED COAL TECHNOLOGY

TUESDAY, AUGUST 9, 1983

U.S. SENATE,
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Blacksburg, VA.

The subcommittee met, pursuant to notice, at 10 a.m., in the auditorium of the Continuing Education Center, Virginia Polytechnic Institute and State University at Blacksburg, VA, Hon. John W. Warner presiding.

Present: Senator Warner.

Also present: Roger Sindelar, counsel.

OPENING STATEMENT OF HON. JOHN W. WARNER, A U.S. SENATOR FROM THE STATE OF VIRGINIA

Senator **WARNER**. This subcommittee hearing will please come to order. Good morning. I'd like to express my appreciation to those of you who have traveled so far to participate in this hearing. These distances have been considerable and I assure you they will be worthwhile. We're going to have a few preliminary remarks. I was asked by a member of the very industrious television crew this morning why I was doing this. I think that should be apparent to all of us. Although the unemployment decline is less than 10 percent, the improved job pictured is not reflected in the coal industry across America. June 1983 found Virginia counties of Buchanan, Dickensor, Lee, Russell, Scott, Tazewell, Wise, and the city of Norton with nearly 18,000 individuals out of work. Men and women anxious to work but unable to do so; 17.9 percent of the total work force in these seven counties are without jobs. Fortunately, the unemployment rate here in Montgomery County is substantially lower. I know the citizens of Montgomery County agree the economic and social hardships that have been imposed on the coal-producing relions cannot be tolerated. An unemployed person is a tragic waste of human resources. Action must be taken to stimulate the mining industry and put these Virginians and indeed Americans, back to work. The economic history of the coal mining is one of peaks and valleys. Today, the coal industry is in a downturn with nearly 30,000 unemployed coal miners in the Appalachian region alone and over 70,000 unemployed nationwide.

Currently, the traditional markets for American coal are not expanding. The National Coal Association predicts 1983 exports will decline by 30 percent or 30 million tons from 1982. Total domestic production will be reduced by 49 million tons or 6 percent from the previous year. This lack of growth in the coal market perpetuates the unemployment miseries of the American coal industry. A total imaginative partnership between private industry and government is necessary to give needed, new direction to the coal industry. New markets must be created for America's coal within the United States and overseas. New markets will put miners and those employed in related industries back to work. Coal technology may be creating these new markets for American coal. American coal can make the United States more energy independent, improve our balance of payments, hence the world environment and put the miners back to work and help to cure economic ills of the coal producting regions.

[The prepared statement of Senator Warner follows:]

OPENING STATEMENT BY SENATOR JOHN W. WARNER

AUGUST 9, 1983

SENATE SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES

BLACKSBURG, VIRGINIA

ALTHOUGH UNEMPLOYMENT HAS DECLINED NATIONWIDE TO LESS THAN 10%, THE IMPROVED JOB PICTURE IS NOT REFLECTED IN THE COAL-MINING INDUSTRY. JUNE 1983 FOUND THE VIRGINIA COUNTIES OF BUCHANAN, DICKINSON, LEE, RUSSELL, SCOTT, TAZEWELL, WISE, AND THE CITY OF NORTON WITH NEARLY 18,000 PERSONS OUT OF WORK. 17.9% OF THE TOTAL WORKFORCE OF THESE 7 COUNTIES ARE WITHOUT JOBS! 17.9% UNEMPLOYMENT, TRAGICALLY, IS NOT ATYPICAL OF THE APPALACHIAN REGION.

THE UNEMPLOYMENT RATE HERE IN MONTGOMERY COUNTY IS SUBSTANTIALLY LOWER. BUT I KNOW THE CITIZENS OF MONTGOMERY COUNTY AGREE WITH ME THAT THE ECONOMIC AND SOCIAL HARDSHIPS BEING IMPOSED ON THE APPALACHIAN REGION CANNOT BE TOLERATED.

AN UNEMPLOYED PERSON IS A TRAGIC WASTE OF A HUMAN RESOURCE.

ACTION MUST BE TAKEN TO STIMULATE THE MINING INDUSTRY AND PUT THESE VIRGINIANS AND OTHERS BACK TO WORK.

THE ECONOMIC HISTORY OF COAL-MINING IS ONE OF PEAKS AND

VALLEYS. TODAY, THE COAL INDUSTRY IS IN A DOWNTURN WITH NEARLY 30,000 UNEMPLOYED COAL MINERS IN THE APPALACHIAN REGION ALONE AND OVER 70,000 UNEMPLOYED NATIONWIDE.

CURRENTLY, THE TRADITIONAL MARKETING METHODS OF THE U.S. COAL INDUSTRY ARE NOT SHOWING ANY GROWTH IN VALUE. THE NATIONAL COAL ASSOCIATION FORECASTS THAT 1983 EXPORTS WILL DECLINE BY 30% OR 30 MILLION TONS FROM 1982. TOTAL DOMESTIC PRODUCTION WILL BE REDUCED BY 49 MILLION TONS OR SIX PERCENT FROM LAST YEAR.

THIS LACK OF GROWTH IN THE COAL MARKET PERPETUATES THE UNEMPLOYMENT MISERIES OF THE AMERICAN COAL INDUSTRY.

AN IMAGINATIVE PARTNERSHIP BETWEEN PRIVATE INDUSTRY AND GOVERNMENT IS NECESSARY TO GIVE NEEDED, NEW DIRECTION TO THE COAL INDUSTRY.

NEW MARKETS MUST BE CREATED FOR AMERICA'S COAL WITHIN THE UNITED STATES AND OVERSEAS.

NEW MARKETS WILL PUT MINERS BACK TO WORK!

TODAY BEGINS A SERIES OF HEARINGS BY THE SENATE SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES TO EXAMINE, INTENSELY, THE COAL INDUSTRY -- ITS STATUS, POTENTIAL, PROBLEMS, AND POSSIBLE SOLUTIONS. FROM THESE HEARINGS I HOPE WILL COME NEW DIRECTIONS AND NEW MARKETS FOR THE INDUSTRY.

(MORE)

IN FUTURE HEARINGS, THE SUBCOMMITTEE WILL FOCUS ON DEEP MINING, SURFACE MINING, INLAND TRANSPORTATION, AND OUR PORTS.

INEXTRICABLY INTERTWINED WITH THE CONSUMPTION OF COAL IS THE CORRESPONDING EFFECT THAT SUCH CONSUMPTION WILL HAVE ON THE WORLD'S ENVIRONMENT.

RECENTLY PUBLISHED STUDIES ON ACID PRECIPITATION CREATES A PERCEPTION THAT CONTINUED USE OR EXPANDED USE OF COAL WILL NOT BE BENEFICIAL TO THE WORLD'S ENVIRONMENT.

THE PERCEPTION OF POTENTIAL ENVIRONMENTAL HARM FROM COAL CONSUMPTION IS BEING EXPRESSED THROUGHOUT THE WORLD FROM THE DEVELOPING THIRD WORLD COUNTRIES TO THE MOST INDUSTRIALIZED OF NATIONS.

TO OVERCOME THIS PERCEPTION AND TO EXPAND WORLDWIDE USE OF COAL, IT IS ESSENTIAL TO DEVELOP MORE ADVANCED COMBUSTION SYSTEMS WHICH ARE ENVIRONMENTALLY COMPATIBLE AND ECONOMICALLY FEASIBLE.

DEVELOPMENT OF THESE SYSTEMS IS A COSTLY, TIME-CONSUMING PROCESS.

AS AN INTERIM MEASURE, THE WORLD CAN USE LOW-SULPHUR COAL

(MORE)

RESERVES. HOWEVER, THESE PRECIOUS COALS ARE LIMITED IN AMOUNT AND GENERALLY ARE UTILIZED FOR THE MAKING OF STEEL. VIRGINIA IS BLESSED WITH A SUBSTANTIAL RESERVE OF THESE HIGH QUALITY COALS.

FOR THE WORLD'S LONG-RANGE DEMAND, THOUGH, ADVANCED COMBUSTION SYSTEMS ARE ABSOLUTELY NECESSARY BECAUSE LOW-SULPHUR COALS WILL NOT ALONE MEET THE FUTURE ENERGY NEEDS THAT ARE PREDICATED.

MY TALKS WITH THE ENERGY LEADERS, FOREIGN COAL-BUYING DELEGATIONS, UTILITIES, CONSUMERS AND OTHERS IN THE AMERICAN PUBLIC HAVE CONVINCED ME THAT THE BIGGEST CHALLENGE THE AMERICAN COAL INDUSTRY FACES IS TO DEVELOP AND AGGRESSIVELY MARKET NEW COAL TECHNOLOGY. NEW COAL TECHNOLOGY WILL IMPROVE THE EFFICIENCY OF COAL BOILERS AND IMPROVE ENVIRONMENTAL COMPATABILITY OF COAL BURNING.

ADVANCED COAL TECHNOLOGY CAN BE UTILIZED TO MEET THE WORLD'S ELECTRICAL, INDUSTRIAL AND HOME HEATING NEEDS.

(MORE)

I HAVE ASKED LEADERS IN THE DEVELOPMENT OF THIS TECHNOLOGY, THE USERS AND THE FINANCIERS OF ADVANCED COAL TECHNOLOGY TO APPEAR BEFORE MY SUBCOMMITTEE TO OFFER THEIR VIEWS OF THE CURRENT STATUS, FUTURE POTENTIAL OF THIS NEW MARKET AND DISCUSS THE PROBLEMS WITH BRINGING IT ON LINE. I HAVE ASKED YOU HOW INDUSTRY AND GOVERNMENT CAN FORGE A PARTNERSHIP TO DEVELOP A CLEANER, BETTER UTILIZATION OF OUR COAL RESERVES.

AS I BELIEVE THIS TECHNOLOGY OFFERS MUCH TO THE INTERNATIONAL COMMUNITY IN THEIR SEARCH FOR CHEAPER, ABUNDANT ENERGY FUELS, THE OFFICIALS OF THIS ADMINISTRATION IN CHARGE OF PROMOTING AND FINANCING THE EXPORT OF AMERICA'S ENERGY RESOURCES ARE HERE TO GIVE US AN OVERALL PICTURE OF SELLING OF AMERICA'S TECHNOLOGY OVERSEAS.

ONE MEASURE I BELIEVE THAT CAN BE INSTITUTED IS TO SEE THAT THE FEDERAL GOVERNMENT MAKES CERTAIN THAT SIGNIFICANT AMOUNTS OF EXPEDITED ASSISTANCE IS MADE AVAILABLE THROUGH NATIONAL AND INTERNATIONAL FINANCIAL INSTITUTIONS FOR THE PURCHASE OF AMERICAN ENHANCED COAL TECHNOLOGIES BY FOREIGN COUNTRIES.

ANOTHER PROPOSAL WHICH HAS BEEN SUGGESTED IS TO LINK A LOAN AGREEMENT CALLING FOR THE PURCHASE OF AMERICA'S COAL TECHNOLOGY WITH AN EXPEDITED FINANCIAL PACKAGE TO A LONG-TERM CONTRACT FOR THE PURCHASE OF AMERICAN COAL.

(MORE)

I LOOK FORWARD TO DISCUSSING THESE MEASURES AND OTHERS WITH THE WITNESSES.

IN CLOSING, I BELIEVE THAT ENHANCED COAL TECHNOLOGY WILL:

--IMPROVE PRICE COMPETITIVENESS OF COAL,

--MAKE THE U.S. MORE ENERGY INDEPENDENT,

--ALLOW FOR MORE TYPES OF U.S. COAL TO BE CONSUMED,

--IMPROVE OUR BALANCE OF PAYMENTS,

--ENHANCE THE QUALITY OF THE ENVIRONMENT,

AND, MOST IMPORTANTLY TO THIS SENATOR FROM THE COMMONWEALTH, IT CAN PUT VIRGINIA MINERS BACK TO WORK AND HELP CURE THE ECONOMIC ILLS OF THE COAL-PRODUCING REGIONS.

(#)

Senator **Warner**. We have an outstanding panel of witnesses scheduled throughout the day who have come from afar to contribute. I have requested that they make their statements in full if they so desire. The subcommittee will be looking to each of you for guidance and the opportunities to develop new foreign and domestic coal markets, and intensive research to develop marketing packaging, hense coal technology. I look forward to today's testimony and I hope during the course of the day to personally meet each of you. Gentlemen, we will get underway with our first witness, Mr. Gerald Blackmore, executive vice president, fuel supply, AEP Service Corp., Lancaster, OH. He is the U.S. representative, Coal Industry Advisory Board for International Energency Agency, Paris, France.

STATEMENT OF GERALD BLACKMORE, EXECUTIVE VICE PRESIDENT, FUEL SUPPLY, AMERICAN ELECTRIC POWER SERVICE CORP., AND U.S. REPRESENTATIVE TO THE INTERNATIONAL ENERGY AGENCY'S COAL INDUSTRY ADVISORY BOARD

Mr. **Blackmore**. I think it is always helpful at a hearing when you are presenting evidence and trying to fly kites, suggest a united approach as to what might be done to resolves a problem, to review what he's said against a background of witness and it might be, in fact, some kind of self aggrandizement. To help you in the way, you should know what he has done in life before you hear what he has to say. I have had the privilege of working for the coal industry for 42 years in several countries; 25 years in Britain and 9 years in different parts of Canada. As you know, American Electric Power is the largest single burner of coal in the United States, and relies on the coal for 90 percent of its electrical generation. The last 3 years, I've been U.S. representative of the CIAB which is the Coal Industry Advisory Board to the International Energy Agency in Paris. The objective of that body is to offset the use of oil by increased use of coal. Therefore this hearing is very pertinent to the objectives of the CIAB's work in support of the IEA. Therefore, I commend the term of reference to this particular hearing. I think its terribly important to review the whole background as to why coal is the priority for the future. To understand why coal is important you must go back to the year 1969. Just prior to that time, which is about the time I came to North America, you could import a barrel of oil on the east coast for $1.68 and we know where that has gone of course, in the last 15 years. It got up to a high of $36 and is now back to $29. And I respectfully suggest you have to ask yourself the question, just how long is that going to hold? There are some people across the world who will say there is plenty of oil available today, the price is down, thus we should retract or not carry on with our efforts to replace oil with coal. I think people who say that are, frankly, stupid because I believe our national security and independence relies on being less oil dependent than in the past. And that also applies to other countries of the free world.

The CIAB was set up in 1978 and is composed of 35 representatives covering 21 of the non-Communist countries that consume 80 percent of the raw energy used in the free world. Therefore, their views are very important. As a background—I notice I'm billed to give an international flavor to this—I believe that charity begins at home and therefore if you can't prove the value of what you're doing at home, it is questionable whether you can set it for the international scene.

When we look at the international potential on page 4 of the booklet, you will see a chart. This is from the world coal report put together by Prof. Carroll Wilson of MIT, 1979. It shows the world potential for exports and it shows the U.S. potential. And you will see in the column on the left that in the year 1982, when we exported 105 million tons and the vast majority was met coal. In analyzing this future, both at home and abroad, I believe we have to confess to this by asking a series of questions. On page 5, I really start by asking the first question. Are we going to accept the fact that coal is not an end in itself? It is only one form of raw energy which has to compete with other forms of raw energy—water, oil, natural gas, and nuclear. All of which are marketed with a narrow band of quality variation. In short, coal might be a great raw energy source for energy independence, but the user—and that's the guy who counts at the end of the day—will not increasingly adopt it if it is not economic and its use does not optimize the cost of the user's end-product. Against this introduction, I think it is important to address certain questions and the probable answers.

Question: Of all the traditional and future uses of coal both at home and abroad, where does the greatest potential lie? I suggest that in the next 10 or 15 years, known quality must control the vast majority of the market. I'm not against new technology. I think its a need to constantly evolve it. But the thing that will make an impact on the 30,000 coal miners out of work in Applachia are the applications of known technology on a sufficient basis. Prospects on the metallurgical market are not good. Most coal operators at home will agree, there is little or no big potential for an increase in metallurgical coal over and above those established when the economy is at a reasonable level. I believe we have to accept the fact that the last 25 or 30 years, mostly led by the Japanese, there's been a tremendous evolution in the blending of coals for turning out high-grade coke from lower grade coals than were previously thought to be necessary. In America, by and large, we've been spoiled because we buy high-grade met coal and low-grade met coal and high-volatile met coal and low-volatile met coal, both of excellent quality, which have turned out first-class coke. Other countries, who really did not have the technology, but good quality coke may be made from second-grade coal. The Japanese have led that thrust.

I think when we take the thermal side where the great potential is, we must recognize that in this country in the last 8 years we have moved from 400 to 600 million tons a year and there are many people in the world coal study who forecast that could be 1 billion tons by the year 2000. The question you ask, gentlemen, is what have we got to do to make it happen? It is not going to happen by us sitting here and just talking about it and these are the questions I try to address. Whenever you are trying to address any question, you have to review the past history to see whether what was done in the past is of necessity the things that will make it happen in the future. On page 7, table I, there are some interesting statistics to show the amount of electrical generation that has been produced by the various raw energy sources. I am sticking with the electrical generation industry because, in terms of potential of those, that is basically where it is.

I should spend a little time talking about the industrial use of coal. Page 6, paragraph (c) I point industrial use was 68 million tons in 1979, and in the view of the American Subcommittee working on behalf of the CIAB, it is thought to be—could have a potential 155 million tons by the year 2000 and that is something not to be sneezed at certainly for the Appalachia producers, who have excellent coal for that particular use. I think in table II, page 7, its interesting to not that since 1973 the electrical generation from coal has increased from 45.6 percent to 53.8 percent and there are all sorts of ways and means that that could be further increased. I will respectfully suggest we know, for example, that there is some potential for 35 million tons more coal burn on the east coast arising from the displacement of oil. Why is it not going to happen as quickly as it may have done? I think the answer to that, to some extent, lies in the problem of communicating with those State and Federal agencies which condition the revenues of the electrical generation industry. After all, the electrical generation industry by and large, which you regard as a private enterprise, their management represent their shareholders and must constantly take their shareholders interests into some account. They cannot be expected to invest vast sums of money unless there is a reasonable hope of return. Therefore, that is a conditioning factor on the one hand to the replacement of the oil burning capacity in the East, in particular. The other factor is the environmental factor which I'd like to touch on in a minute.

Exhibit 2, which may have already appeared, shows the projected U.S. industrial demand for coal climbing to 155 million tons in 1990. Later on in my, hopefully, not too long presentation, I'd like to explain what needs to be done to make that practical.

Question 2, on page 9. What are the constraints and parameters to be addressed if we are gong to have the opportunity of burning more coal in this country within this generation and export more coal for other generations throughout the world? I believe the first thing we all have to consider is the environmental concern. We've been talking about acid rain and I haven't read the report yet which highlights what it is or whether it has been established that it does some damage. I think a pertinent fact is that we should not get involved in passing legislation to correct this problem, certainly legislation which would cost this country a bundle of money particularly in the midwest, the heart of the industrial scene in the United States. If some of the Senate bills currently proposed were implemented, it would increase the cost of the unit of electricity in the Midwest by about 60 percent? Do we recognized the impact on the coal industries of the Midwestern States of Illinois, Indiana, Ohio, Western Kentucky? Do we recognize what impact it would have on the economy of those States and do we recognize the impact that it would have on our potential for exporting goods? The use of electricity in industry in this country is the highest in the world. Use of electricity per capita by John Q. Public is the highest in the world. The move of implementing one of those

Senate bills would have a tremendously adverse effect. I raise the question and we'll come back to it of whether there isn't a need for a time phased program? In terms of dealing with the alleged acid rain problem, we should have a more balanced approach until scientific evidence comes to light which proves categorically that acid rain does have a real high adverse impact.

QUESTION 3, on page 10. You might say, well if the coal used by the electric generation industry is increased from 400 million tons in 1973 to 600 million tons in the last couple of years, what has been the level of sulfur dioxide emission? From all the Government reports which we've analyzed it's fair to say there are less bulk tons of SO_2 being emitted today for the burning of 600 million tons coal compared to what it was when it was 400 million tons of coal being burned. And I'm prepared to analyze that in detail if anyone so wishes. In other words, I respectfully suggest the much maligned electric utility industry in its various forms has done a pretty substantial job in reduction of SO_2 emissions and has taken a high degree of responsibility in containment of SO_2. The question is, how have they done it?

Page 11. Some have done it by switching to lower sulfur coals. I think the most progressive companies have done it by sticking with their traditional sources of supply and washing those coals using prudent modern technology and done it on a cost efficient basis. Some people have done it by scrubbers and I don't want to deal with that subject. It's a very expensive way of achieving the objective. I think its fair to say in the year 1982 there was something on the order of 1,150,000 tons of SO_2 removed from the smoke stacks of this country by scrubbers, which is still a small part of the total sulfur alluded to.

QUESTION 5. What is the most cost effective technique? I think I'm on record in a number of places that the most cost effective technique is to use comprehensively washed coal washed at an economic level. But looking at this whole question of cost effectiveness, we have to take in mind in my view, that any solution should take into account low-cost electricity over a period of years. We have to recognize in this country and across the world that there are thousands of different trains of thought turned out every day of the week on this subject. They had pithead prices of varying degrees from, shall we say, $5 in South Africa to as much as $50 in the United States. And these must all be related in terms of the coal energy picture, the integrated economic approach. We have to recognize that the lowest cost of a ton of coal does not necessarily give rise to the lowest cost of electricity and later on I'll give a format to suggest what has to be done to analyze the integrated economics.

On page 12, I raise a question which I think is very material in looking at the future. Have the economics of electric generation and the market potential for the future from coal changed materially in recent years? In the last 13 years, coal has gone from $3 to $4 a ton to anywhere from $25 to $45 a ton. Do we recognize that the capital investment in a surface coal mine way back in 1965 was probably $5 per ton of annual output. And an underground mine, at that time, was probably $10 per ton of annual output. Do we recognize that today to start a new surface mine and comply with all the rules and regulation one must make a capital investment of $40 to $50 per ton of annual output. If it's a comprehensive underground mine, then you're talking about $80 to $100 per capital investment? Do we recognize in this period of time that, if we were directors of an electric utility, and we built a generating plant for burning in the late 1960's it would have cost us about $100 to $110 of capital per kilowatt installed capacity? Those coal burning units that are coming onstream today, I suggest a reasonable figure is $800 of capital investment. What was the interest rate in 1965—5 percent. What is it today—15 percent. You take the multiplier of the increased capital and the increased interest—where does it all get us? It means that it's very vital, if there's something we can do to increase the availability of the low cost capital, then we're going to be ahead of the game. For clearly, if anything can be done to achieve higher efficiency and operation from existing assets we must have major economic savings. Categorically, in doing something about this—it's a matter of opinion—but I think we have to take into account that if we have a boiler which has been well engineered, by and large, it has only been well engineered to a narrow range of coal. And consistency must be a key factor in getting results. I think it's interesting and I quote on page 14, exhibit 4, what are the typical results—the results you get from run mine coal and from partially washed coal. By partially washed, I mean washing the first half inch and letting the thing go back into unclean mined half inch. And the fully washed coal—this is what I believe to be a very typical example, particularly of a high sulfur coal. And, in appendix A, there is a detailed report which I submitted to the Environmental Committee of the CIAB. But I think the interesting thing in the run of mine coal is you have this tremendous variation of Btu's from 8,400 to 10,000. When you've partially washed it, you've narrowed the range. But when you get it fully washed, you get on a fairly consistent basis. Please look at the last line. There's a wonderful example of what can be done in terms of SO_2 direction. You notice with the run of mine coal, the range of SO_2 permitted was from 10.0 to 23.8. With a partially washed make, 8.3 to 12.5. Now you narrow it down to 7.5 to 8.5 when you fully wash it. This is a typical example of what responsible utility and a responsible coal operator can do to materially reduce SO_2. And as the appendix A will show you, in actual fact it cost nothing in terms of increasing the cost. In other words, as the result of doing this, you not only increase your availability but you made it possible to put enough Btu's into the boiler to get the original plate capacity. There are many boilers and many utility plants in this country that never get their plate capacity for a number of reasons. This is the argument of doing things to maximize the use of the imbedded capital and it was found they increased, or got 50 megawatts of their plate capacity they couldn't previously get purely from the higher Btu. Naturally, the critics of this sort of approach will say immediately, that washed coal costs you more money. And the answer, of course, is yes. But in analyzing this, you have to understand the economics of what we call the coal energy system, which is shown on page 15 of exhibit 5. I suggest it requires a recognition of all components of cost incurred by the user, not only the pithead or cost of coal at the mine, but all those involved;

namely, the intergrated coal energy cycle as depicted on the chart. This pictorial representation deals with the electric generating industry which is appropriate since this market accounts for some 83 percent of all the coal burned in the United States. Based on the WOCOL information already shown in exhibit 1, this market represents not only the potential for U.S. coal but the international scene as well.

Equally important are the design characteristics of the boiler in which the coal is to be utilized and a recognition of the narrow range of qualities which existing individual boilers can burn and achieve a high level of availability, thereby minimizing the cost of a unit of electricity. In recent years, manufacturers have specifically designed boilers to efficiently accommodate a wider range of coals.

Identifying the physical and chemical characteristics of the coal is vital to minimizing the slagging and fouling in boilers which are the mitigators against high availability. Coal washing contributes to reduced slagging and fouling by reducing the amount of ash and providing a consistent product. This is a very complex subject which cannot be dealt with in detail this morning, but to illustrate, I give a number of nomograms and, in support in the book, you will find in appendixes B, C, and D are further notes from my engineering colleagues that might be helpful. I say these nomograms are self-explanatory; they aren't, really. So on page 17, if we can get exhibit 6 on the board. This is a typical Ohio No. 6 coal and, on the left-hand vertical axis the indixes are the pound of ash as received. On the lower left side is the base/acid ratio control. And the right-hand side bottom half horizontal axis is the ash softening temperature. You will see that with this coal unwashed you get a figure starting at nearly 17 and it follows the format down and at the point where it hits the vertical point of the base/acid ratio, you go vertically across and you will see that where it hits a vertical point from the ash using temperature, coming up, you get an area which is plus very severely for slagging total. If you wash that coal, and its a very simple coal to wash, its almost a black-and-white situation. You will find you can get it down to 5 pounds of ash per million Btu, on a very economic basis. You will see that the base/acid ratio determines the number—the No. 6 coal rises to about .94. Take that line across and where it integrates with the vertical line of the ash softening temperature you will see you get in the medium area for slagging coal. We have spent a lot of time on the Ohio No. 6 coal because we have a station called Covesville with a capacity of 245,000 megawatts, which has always been a very difficult station. It sits on about 150 tons of Ohio No. 6 coal. It is the obvious coal to put in there, but unless you wash it comprehensively then you can't get higher availability. The next one is a Pittsburgh 8, which is another interesting scene, the most prolific scene in the country. And the same thesis applies. You will see that if you use or attempt to use unwashed Pittsburgh 8 that you are in a very severe slagging angle, but if you wash it, you get it down to very low. And that last one, because I was trying to be selective in putting this forward, is a Utah coal with which we have had some personal experience with over the country. And you see here again, in the unwashed condition it is in the high range. Page 18, exhibit

8. When you wash it, you get into the low range. In each of these cases, you are talking about massive increases in availability which means fixed annual capital charges are lessened. So, in question 11, you might say you appear to believe there are tremendous merits in spending much time and money on the analysis of the "Coal Energy System" for each individual plant. Can you justify it? And my answer, charity begins at home. And I respectfully suggest that you look at the table on page 19, which are quotes from the AEP Annual Reports for the last 3 years. I respectfully suggest that when 50 percent of all your costs are for fuel, all a corporate responsible efficient management has to do is—and I think we can fairly say is that in the seven States where we have the privilege of doing business in this country, our electricity costs are either the lowest or next to the lowest. So whilst we have a wash coal alternative and the means of reducing SO_2, but as a means of getting higher availability and better utilization from the imbedded capital, we have not done that at the expense of the customer but, all these things locking together, if you accept the thesis of the integrated planning. You might say, well, how does this apply on a countrywide basis? There are some 250,000,000 kilowatts of plate capacity, coal-burning capacity for electric generation in this country. Its difficult to get the actual statistics, but I believe the general level of availability across the country is about 66 percent. We, in AEP, are very proud to say we get 78 percent. I have already made the point on how we do it at no expense to the customer per unit of electricity. We do not suggest that what we do can be universally applied, but we think its something that possibly should not go disregarded. And when you apply this thesis to the broader market, not only in the United States but the export market, this key factor of transportation.

There can be little benefit if you establish, in this country, that washed coal on a consistent basis is attractive to everyone, your shareholders, SO_2 reduction, the bottom line. And we find that we can't afford to spend more than $7 on transportation before it hurts. Then surely it must be applicable to our potential importers, where in recent years they have been spending 50 percent more of delivered cost on transportation. Therefore, on page 20, question 12, I address the question of transportation. And, in exhibit 9 at the top of page 21 I, in effect, again address the philosophy and thinking that has to be applied if we're going to satisfy the economics of the industry. You know, America might be the great free country and might be able to react to world demand for coal, but we are still in thermal market a swing supplier. I will say once now and later, how many coal operators in the United States have a long-term contract from an importer for thermal coal? If you know of one, please correct me. I don't know of anyone who's got a categoric, long-term contract. And, therefore, his economics at the end of the day must be the criteria and I respectfully suggest the importance of transportation is an important proponent in terms of his economics. And this is possibly the competitive position of U.S. coal. It's heavily affected by transportation, economics, proponents of slurry pipelines, offshore islands and superports would argue that unless the Nation can export most of its coal in supercolliers the United States will not become a major exporter. Later on, I will raise some questions on that. And I think there were a number of questions raised on this in "Coal Trans 82." In effect, what have I suggested so far that the experienced—certain companies in the United States, as you can only guess, the right bottom line for an electric generation control is by integrating the economics. I respectfully suggest that, because every boiler is different and has a narrow range of coal which can maximize its availability, then this idea of having a big boat into which you put 15 or 20 different types of coal, all bearing different characteristics of maybe all different ash Btu's and temperatures and you throw it together on the east coast and deliver it is possibly not the way to go if you want to develop and put together a long term coal export market. I suggest very respectfully, because each boiler bears that you would, in fact, the end-product user needs to select his coal very carefully. And when you come to selected coal than the importance or math of transportation might be very different. I tried to size it up on the page 23. On this subject, for the benefit of current investors or future investors, I would like to make several points and then raise a question. If the thesis I have previously argued; namely, and the economics of the end-product user can only be achieved by a selective product; that the delivery of selective produces does not of necessity lend itself to the use of high-capacity boats and terminals which, in turn, require costly dredging; then, unless the potential customer is prepared to commit himself to long-term contracts which give reasonable reimbursement for the new investment; then should not the U.S. investor beware of the potential liability and high risk in new port developments which require near capacity utilization before the investment gives a reasonable rate of return?

I touch in question 13 on this industrial coal, which I previously commented on as having a potential of from 68 to 155 million. I address two points on page 24. You can't generalize, but I will make two points. First, normal industry steamboilers operate in and around 1,500° F. At this temperature, high sulfur coals can have a large part of their sulfur neutralized by the admixture of limestone. Hence, the environmental problem can be more easily and economically handled. Second, all feasibility studies of conversion of oil burning boilers and/or gas industrial steamboilers or new installations show that the capital investment on a coal-burning boiler is appreciably higher with coal than with oil and gas. The payback, therefore, is longer but its still there. And there are a number of questions which this hearing is addressing. What can government do? Well, in terms of expanding the industrial use of coal in Europe, it is well known that the governments of some countries certainly United Kingdom and France, have followed the recommendations of the IEA and arranged for the availability of substantial sums of low-interest capital money to encourage the higher industrial use of coal.

There might be some who would argue that this is a form of subsidy which is undesirable, but I believe that the factor of independence of energy plus the fact that you will do something to encourage the stability of the coal production in the high-sulfur state by this device. Alternatively, I am sure there is a system of preferred tax benefits, but I am just a coal miner and not a tax specialist.

Certain people have been into this in great depth and fully recognize the fact that the lower interest rates are in the best interest.

QUESTION 14. In your answers so far, you seem to indicate the opportunities for the United States in the next 10 to 15 years are based on the integrated planning and use of known technologies. How do you view the potential for new technology?

I suggest that all forms of R&D should initially be reviewed for their business potential and, therefore, the view of the businessman is important. In presenting new technologies for coal to the business community, two major parameters must be, I believe, made clear. Whatever the superficial merits of coal are in its delivered form, it must first of all, over the depreciation life of the asset in which it is burned or utilized, contribute to the competitiveness of the user's product. And second, it must do this in an environmentally acceptable manner, taking into account overall economics. This indicates strong justification for coal of consistent quality being fundamental to both these business parameters. Additionally, the environmental concerns being expressed in the United States in recent years—the acid rain argument, for example—are of equal or greater concern in many countries to which U.S. coal might be exported. I would draw your attention to the CIAB, the report on "Coal Use and the Environment," as being a pretty fundamental document for anyone who wants to export coal and particularly to Europe. And if you don't understand the way they are attacking their environmental problem then whatever the value of coal it might be a complete waste of time. Therefore, the real potential for meaningful R&D from a businessman's standpoint is back to these two parameters. In short, an emphasis preferably on precombustion or during combustion desulfurization which will achieve overall economic benefits. I do not presume to be qualified to address other technologies but I am sure there will be subsequent witnesses who will deal with fluidized bed combustion, various forms of chemical coal beneficiation, and various forms of electrostatic sulfur and ash removal beneficiation systems.

In the field of oil replacement by coal, a continuation of the R&D on coal/oil mixtures but more particularly, in my judgment coal/water mixtures, have tremendous merit. In either of these cases, modern technology is critical because I believe a low sulfur content and the lowest possible ash in the coal fraction must be highly desirable. In short, the potential, first at home and subsequently abroad is tremendous, but only under the coordinated and integrated terms I have suggested.

In your answers you have laid great emphasis both in the United States and overseas on the impact environmental decisions will have on the future of coal. There's no doubt about this. This is the biggest thing in this country in determining the future of the coal industry and it also applies, in my view, across the world. My answer, I don't think it was prudent to expand on what some of us believe very clearly on. First of all, I have indicated that any support for some of the bills before the Senate would not aid in the 12 billion tons SO_2 reduction. I respectfully suggest our only interest at this stage is that there isn't the slightest sign any proof that they would make any difference. I believe there is a great need to have what I call a time phase approach to this. I have already indicated it would increase the burning of coal, the electric generation industry for the last 8 or 9 years by 50 percent. I would suggest there's a moral to that story and I believe quite fundamentally there can be a sizable reduction in the SO_2 achieved in this country in a short period of time with the extension of comprehensive coal washing on an economic basis without making a material impact on the cost of the unit that exists. This is far more quick in its reaction than going the routes which will be demanded by the bills I previously referred to. It would have little impact on cost of unit of electricity and remember that 60 percent increase figure I talked about a little earlier. In short, I commend that approach to those who are thinking about the problem and I can rationalize on a basis that every year we are producing a reduction. And all the records will show that.

QUESTION 16. On page 28, at an early stage in your presentation you applauded the term of reference for this meeting but it would appear in your questions and answers that you have completely disregarded them. I accept that superficial conclusion implied by the queston. But I defend my approach on the basis that unless there is an integrated understanding on the problems from the coal face through to the busbar in the case the electric generation industry or, in general, a recognition of the economics of the end product user, the agreed massive potential for coal, both at home and abroad, will not be achieved. In these circumstances, I raised the question whether a reliance on past marketing techniques to achieve this potential will be successful. I think the justification of this question is covered by the next question. What U.S. coal companies have long-term export orders for thermal coal? To the best of my knowledge, very few, if any.

In short, the increase in export sales which gave rise to the optimism of the 1978–81 period was based on the oil shortage and the United State today remains as the swing market supplier. Its ability, that is the U.S. coal industry's ability, to react faster than any other international export supplier is recognized, as is its ability to supply immediate demands without long-term commitments.

I would suggest that there is no more efficient or highly competitive force in world mining than the U.S. coal industry. But I respectfully suggest that in the thermal world market these advantages, these abilities are being misused and disability is used to our detriment because we have not got any long-term contract.

QUESTION 17. Are you prepared to make any recommendations for consideration by those who have the power to assist? I respectfully suggest the most pressing requirement in the United States is a phased economic resolution to the problem of so-called acid rain which duly takes into account economic factors and scientifically supported consideration. Second, a recognition by those who control the utility revenues. The lowest cost ton of coal does not of necessity produce the lowest unit cost of electricity. Also, a recognition of the value of consistent quality coal, of appropriate ash characteristics, in achieving sulfur dioxide reductions, optimizing boiler availability and lowering the cost of a unit of electricity over a period of time. At all times the importance of the economics of the end-product user must be the ultimate criterion for answers.

No. 4, a recognition that the vast capital expenditures in coal mines, transportation and port facilities constitute a very high risk if not supported by long-term contracts. These investments are hazardous if dependent on a swing market supplier situation. And last, that traditional marketing techniques will no longer be successful for thermal coal unless there is an understanding of the overall economics covered by the graphics of "Coal Energy System", exhibit 5, and the transportation infrastructure, exhibit 9. In short, in the overall "Coal Energy" approach each marketplace might demand a more selective product to produce the better bottom line for the user's end-product and the transportation requirements might be very different in that selective product.

How would you suggest the marketing aspects of these problems might be tackled? If the integrated approach to satisfying the economics of the end-product user is accepted then there is a need for the forming of consortiums by the energy producers and users who have the experience and proven know how of integrating the technology and economics from the coal face through to the end product user. From this integrated base, coal specifications can be designed, supplies arranged and associated transportation services incorporated, with each investor getting a fair share of the rewards, taking due account of the investment that each has at risk.

Do I believe that such expertise is available in the United States? Yes. It's categorically yes. A number of large electric utility companies have in recent years set up such organizations. The efficiency of each one can be judged on its operations and proven results in this country. Engineering principles and technology do not vary appreciably. Know-how and implementation costs do.

Finally, I come to the point of new technology.

QUESTION 20. I support this, I'm afraid, since we must for national security balance of payments carry on with new technology to further reduce importation and/or use of oil and natural gas. Second, to reduce sulfur prior to combustion. And third, and I believe this fits right in with the time-phased development of synthetic fuels which, quite frankly at the present time, is having difficulty finding matching investments. But I believe if you accept the fact that in about 10 or 15 years to develop it and improve the production potential, then there's a great need to have control. I do respectfully suggest, on page 32, getting back to the term of reference to this panel, the business approach to any R&D work should be a priority and, again, charity should begin at home. I raise the question as to whether it is a good business technique to attempt to sell technology offshore which has not proven beneficial in the United States.

Thank you very much, Senator Warner.

[The prepared statement of Mr. Blackmore follows:]

A DISCUSSION ON ENHANCED COAL TECHNOLOGY — COAL'S MARKET FOR THE 80's

Testimony by

Gerald Blackmore

Executive Vice President — Fuel Supply
American Electric Power Service Corporation
and a
U.S. Representative to the
International Energy Agency's
Coal Industry Advisory Board

U.S. Senate Subcommittee
On Energy and Mineral Resources
Blacksburg, Virginia
August 9, 1983

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International Energy Agency
Paris, France

Introductory Comments

Mr. Chairman:

It's a great pleasure to have the opportunity of appearing before this panel today. As a background and an experience justification for my comments and observations, I believe it might be helpful if I reviewed my activity in the coal industry covering a continuous period of 42 years.

The first 25 years were spent with the United Kingdom's National Coal Board, culminating with a senior position on the Board's Headquarters Staff. I left that position to go to eastern Canada in 1968 to become first vice president of the Coal Division of the Cape Breton Development Corporation. I believe I had some small part in the rejuvenation of the coal industry in that part of the world helping to build the sales of thermal and metallurgical coal and coke not only in this hemisphere but to various European countries as well.

I moved to western Canada in 1972, spending nearly five years in the Province of Alberta as the chief operating officer of a coal company exporting coking and thermal coal to Japan, other countries of the Pacific Rim and Europe.

I have now had the privilege of working for American Electric Power for nearly seven years. As you know, AEP, with its associated companies, is the largest single burner of coal in the United States; in fact, in a normal year, excluding recession periods, we probably burn somewhere in the order of 8-9% of all the coal burned by the U.S. electric utility industry or over 50 million tons per year. Therefore, I think I can say I have that broad type of experience in the various facets of the coal industry which are the basis of some ideas which might be of value for consideration by your committee.

Of particular relevance, I've been privileged over the last three years to be an American representative on the Coal Industry Advisory Board to the International Energy Agency in Paris. It follows, then, that many of the thoughts have a relevant international flavor.

The guidance given to witnesses for this hearing is very pertinent at this time, namely,

> "Testimony should focus on the status of enhanced coal technology and its potential for improving the quality of our environment and increasing coal use by developing new markets, foreign and domestic. The hearing is to examine the research, development, marketing, and packaging of advanced technology and what incentives are needed in financial, marketing, regulatory and legislative fields to maximize coal's potential in the domestic and international markets."

Naturally, this leads to the question of why coal, in the last fifteen years, has become more and more important.

We have to go back to 1969, when the first action of the OPEC countries had an impact on oil availability. We have to recognize that in this period of fourteen years, the cost of a barrel of oil has increased from about $1.75 on the East Coast of the United States to as high as $34-$36 in recent years. When the current depressed price of $29 or thereabouts has to be viewed in the context of an oil glut and a recessionary economy, we must then question whether that general price level will hold -- or whether the OPEC countries will not take the first available opportunity to again put pressure on the free world.

The history of the last fifteen years highlights the fact that it is vital, in fact, crucial, for any free country to be independent in terms of its raw energy supply not only for national security but also for control of balance of payments.

Concern for these factors was the basis for the formation of the International Energy Agency in 1974 by 21 of the non-communist countries that consume 80% of the raw energy used in the free world. The Coal Industry Advisory Board (CIAB) was formed in 1978 because the IEA's ministers very clearly appreciated the contribution that coal could make to energy independence. This contribution was detailed in the World Coal Study, (WOCOL) published in 1979.

Exhibit 1, reproduced from the World Coal Study, shows the potential for coal exports with particular reference to the United States.

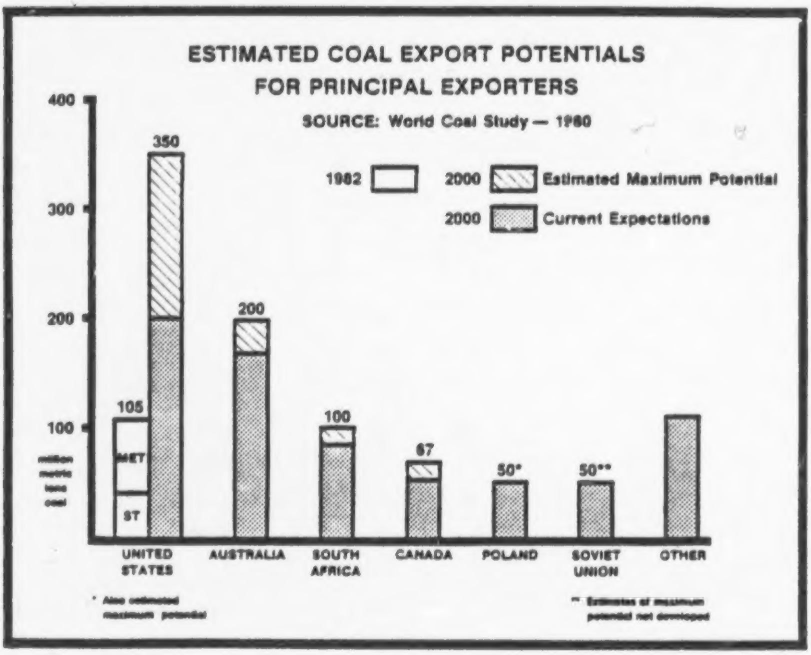


Exhibit 1

Coal is attractive, in principle, as a raw energy source because of its geographically distributed availability and its cost competitiveness.

In addressing coal's potential, one must recognize that it is not one homogeneous commodity. Many observers of this raw energy scene do not recognize that around the world, there are thousands of different grades of types of coal, taking into account ash characteristics, which are produced every day. Frequently, many of these coals are marketed in an unwashed condition and therefore present to the user a product of inconsistent quality.

Coal is not an end in itself. It is one form of raw energy which has to compete with other forms of raw energy, namely, water, oil, natural gas and nuclear, all of which are marketed with a narrow band of quality variation.

In short, coal might be a great raw energy source for energy independence but the user will not increasingly adopt it if it is not economic and its use does not optimize the cost of the user's end-product.

Against this introduction it is important to address certain questions and their probable answers.

QUESTION 1

Of all the traditional and future uses of coal both at home and abroad, where does the greatest potential lie?

ANSWER 1

If one addresses the next 10-to-15-year period during which time, new and at this stage, unproven technology will have little or no impact, it is suggested that:

a) The metallurgical market has little upside potential over that achieved in the past. The use of coal per ton of steel continues to decline across the world; further, the requirement for blending high grade and therefore high-price coals becomes less critical due to better understanding of the physical and chemical interfaces of the carbonization process.

b) The use of thermal coal for steam generation in U.S. electric utility generating plants has already increased from 400,000,000 tons in 1974 to 600,000,000 tons in 1982.

This is highlighted in the tables on the following page. It shows that coal now provides 53% of the nation's electric generation. Also note that oil has dropped from nearly 17% to about 7% and nuclear has risen from 6% to nearly 13%.

It is forecast by some that the potential for coal use in electrical generation in the United States could reach 1 billion tons a year before the end of this century. This, plus the increased export potential shown in Exhibit 1, represents the vast majority of the near term potential for U.S. coal.

c) The future potential of U.S. industrial coal use, which amounted to 68 million tons in 1979, should not be disregarded.

This subject was reviewed in great detail by a committee of the CIAB chaired by Sir Derek Ezra, then Chairman of the United Kingdom's National Coal Board.

TABLE I
ELECTRIC UTILITIES
Net Electricity Generation by Primary Energy Source
(Million Kilowatt-Hours)

YEAR	COAL	PETROLEUM	NATURAL GAS	NUCLEAR	HYDRO	OTHER	TOTAL
1973	847,651	314,343	340,858	83,479	272,083	2,294	1,860,710
1974	828,433	300,931	320,065	113,976	301,032	2,703	1,867,140
1975	852,786	289,095	299,778	172,505	300,047	3,437	1,917,649
1976	944,391	319,988	294,624	191,104	283,707	3,883	2,037,696
1977	985,219	358,179	305,505	250,883	220,475	4,063	2,124,323
1978	975,742	365,060	305,391	276,403	280,419	3,315	2,206,331
1979	1,075,037	303,525	329,485	255,155	279,783	4,387	2,247,372
1980	1,161,562	245,994	346,240	251,116	276,021	5,506	2,286,439
1981	1,203,203	206,421	345,777	272,674	260,684	6,054	2,294,812
1982	1,192,004	146,797	305,260	282,773	309,213	5,164	2,241,211
1983*	296,454	38,024	56,065	71,191	87,570	1,356	550,659

* Includes January-March

Source: U.S. Department of Energy/EIA Monthly Energy Review, June, 1983

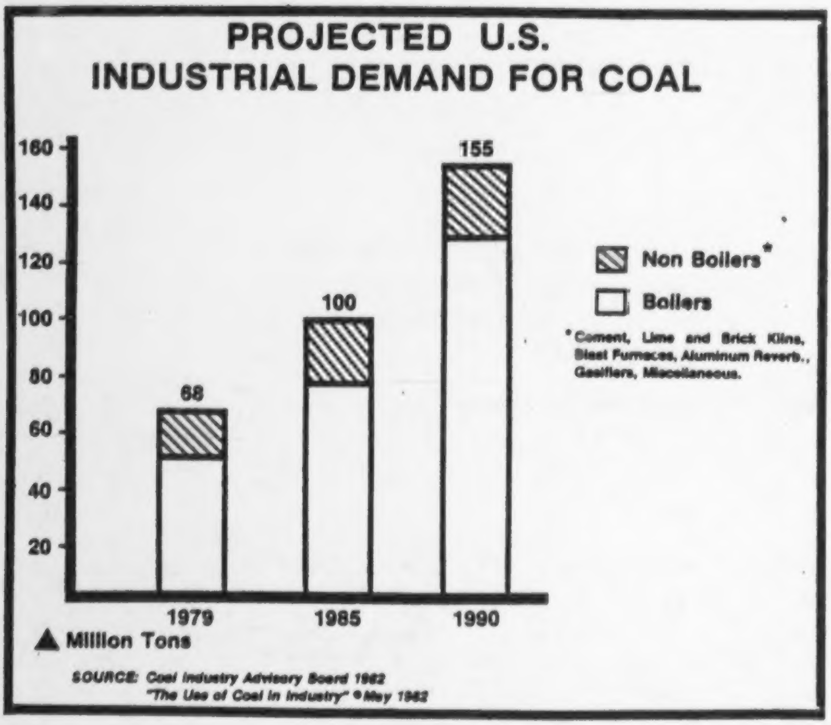
TABLE II
ELECTRIC UTILITIES
Net Electricity Generation by Primary Energy Source
(Percentage)

YEAR	COAL	PETROLEUM	NATURAL GAS	NUCLEAR	HYDRO	OTHER
1973	45.6	16.9	18.3	4.5	14.6	.1
1974	44.4	16.1	17.1	6.1	16.1	.2
1975	44.5	15.1	15.6	9.0	15.6	.2
1976	46.3	15.7	14.5	9.4	13.9	.2
1977	46.4	16.9	14.3	11.8	10.4	.2
1978	44.2	16.6	13.8	12.5	12.7	.2
1979	47.8	13.5	14.7	11.4	12.4	.2
1980	50.8	10.8	15.1	11.0	12.1	.2
1981	52.4	9.0	15.1	11.9	11.4	.2
1982	53.2	6.6	13.6	12.6	13.8	.2
1983*	53.8	6.9	10.2	12.9	15.9	.3

* Includes January-March

Source: U.S. Department of Energy/EIA Monthly Energy Review, June, 1983

Exhibit 2, an extract from this committee's report is a pillar graph showing the potential for the United States. Please note the projected increase of 87 million tons over the next ten years.



PROJECTED U.S.
INDUSTRIAL DEMAND FOR COAL

*Cement, Lime and Brick Kilns, Blast Furnaces, Aluminum Reverb., Gasifiers, Miscellaneous.

SOURCE: Coal Industry Advisory Board 1982
"The Use of Coal in Industry" ©May 1982

Exhibit 2

QUESTION 2

In answer to Question 1, great emphasis is laid on the fact that the vast majority of the potential in the next 10 - 15 years for the use of coal at home and abroad is for electrical generation. What are the constraints and parameters to be addressed to achieve this?

ANSWER 2

First, across the world, the concerns for the environmental effects resulting from the use of coal is understandably the biggest constraint.

This is a problem for governments. Unfortunately, the absence of any precise scientific proof of any direct relationship between sulfur dioxide emissions and acid rain does not assist them in responding to the arguments of the environmentalists.

In every country or geographical community, there is a need for a time-phased plan which provides for factual measurement of the alleged damage and, if necessary, provides for reduction of sulfur dioxide emissions within economic constraints.

It should be recognized that this environmental concern is not confined to the United States. Electors and politicians across the world must recognize the wisdom of limiting capital investment in counter measures until there is some real scientific proof of the cause of the problem.

QUESTION 3

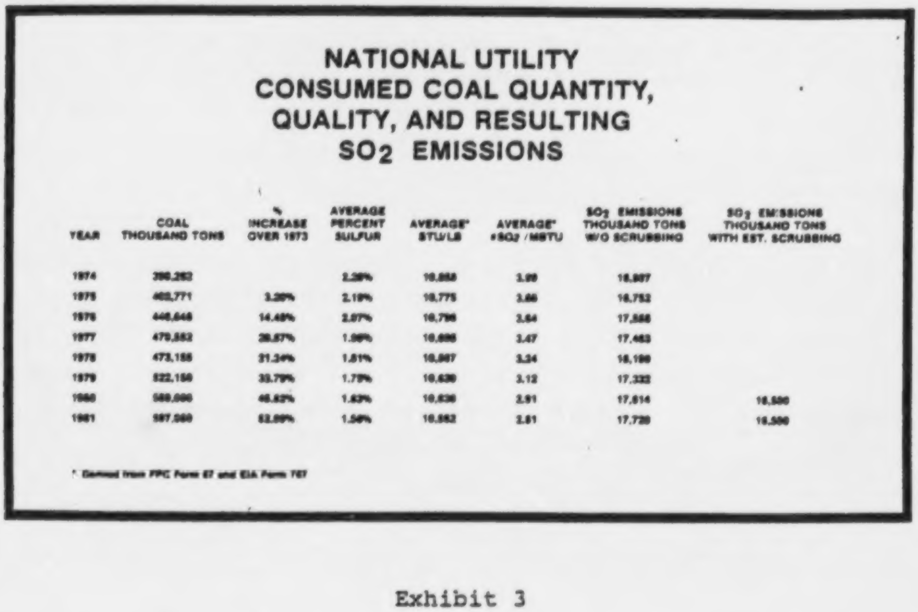
You have already commented on the fact that the U.S. electrical generating industry has increased its use of coal in recent years from 400 to 600 million tons.

What effect has this had on total sulfur dioxide emissions?

ANSWER 3

This answer in general is nil. This is reflected in Exhibit 3 and is developed from U. S. government statistics.

In view of these levels of SO_2 emissions, it is interesting to note that an examination of the numerous recent reports published on the subject of "acid rain" shows no indication of a deterioration in Ph values measured during the same time period.



NATIONAL UTILITY CONSUMED COAL QUANTITY, QUALITY, AND RESULTING SO_2 EMISSIONS

YEAR	COAL THOUSAND TONS	% INCREASE OVER 1973	AVERAGE PERCENT SULFUR	AVERAGE* BTU/LB	AVERAGE* #SO2 /MBTU	SO_2 EMISSIONS THOUSAND TONS W/O SCRUBBING	SO_2 EMISSIONS THOUSAND TONS WITH EST. SCRUBBING
1974	390,262		2.29%	10,858	3.99	15,607	
1975	403,771	3.20%	2.19%	10,775	3.86	16,752	
1976	446,646	14.48%	2.07%	10,796	3.84	17,588	
1977	479,552	22.57%	1.99%	10,699	3.47	17,463	
1978	473,155	21.34%	1.81%	10,567	3.24	16,199	
1979	522,150	33.79%	1.79%	10,630	3.12	17,332	
1980	569,096	45.62%	1.63%	10,638	2.91	17,614	16,500
1981	597,060	52.60%	1.54%	10,552	2.81	17,720	16,500

* Derived from FPC Form 67 and EIA Form 767

Exhibit 3

QUESTION 4

How has this reduction in the amount of sulfur dioxide per ton of coal used been achieved?

ANSWER 4

By a variety of means, namely:

a) switching to lower sulfur coals;

b) using coals washed to varying degrees, which provides for reduced sulfur, increased BTUs and therefore, reduced sulfur dioxide; and

c) installation of scrubbers.

QUESTION 5

Which of these techniques is most cost effective, taking all economic factors into account?

ANSWER 5

Based on experience in the United States, the most cost effective is probably efficient, economic, comprehensive coal washing, but one cannot generalize. However, certain main points can be made:

a) any solution should take into account the importance of low cost electricity over a period of years;

b) the importance of the contribution to the economy of the individual coal-producing states should not be ignored;

c) since electric utility companies are highly regulated, it is vitally important that state public utility commissions and those federal agencies which might be involved, have a complete and comprehensive understanding of all the components of cost that are related to the efficient generation of electricity, both in terms of capital investment and operating expense.

As a start, it should be recognized that the lowest cost ton of coal rarely gives rise to the lowest cost unit of electricity.

QUESTION 6

Have the economics of electric generation from coal changed materially in recent years?

ANSWER 6

The following table gives the appropriate basis for an answer:

	1965	1983	1990
Cost per ton F.O.B. mine	\$3-4	\$25-\$45	
Capital cost of new coal mines per annual ton of output -- surface	\$5	\$40-\$50	
underground	\$10	\$80-\$100	
Capital cost of coal-fired plants per kw electric plate capacity	\$100-\$120	\$700-\$900	\$1,500
Scrubbers cost (extra) per kw of plate capacity	---	\$200	\$300
Interest rates	5%	15%	

QUESTION 7

What deduction can we derive from these figures?

ANSWER 7

Quite clearly, anything that can be done to achieve higher efficiency and operational availability from existing assets must have major economic savings.

QUESTION 8

From your experience, what makes the greatest impact in getting higher availability and efficiency?

ANSWER 8

Categorically, the feeding to the boiler of the appropriate grade of coal of a consistent quality, with due regard to ash characteristics, taking into account the environmental standard required to be achieved. This in most cases means a completely washed coal.

QUESTION 9

Can you offer an example of the consistent coal quality you refer to?

ANSWER 9

Given at Exhibit 4 is one excellent example of the improvement in quality arising from varying degrees of coal washing.

EFFECTS OF COAL WASHING

Muskingum Preparation Plant

	Run of Mine	Partially Washed	Fully Washed
BTUs	8400-10000	9600-10800	11100-11500
Ash%	20-32	16-24	11-14
Sulfur%	5.0-10.0	4.5-6.0	4.3-4.7
Moisture%	4.0-7.0	5.0-7.2	7.8-8.6
Yield%	100-100	90-96	83-87
SO_2 (#/MBTU)	10.0-23.8	8.3-12.5	7.5-8.5

Exhibit 4

The chart is an extract from a contribution by AEP to a CIAB report, given in full at Appendix A. It shows a comparison of run-of-mine, partially washed and fully washed coal for AEP's own Muskingum mine. Note the reduction of SO_2 per million BTUs which was achieved by comprehensive washing. Conversion to the fully washed coal at the Muskingum River Power Plant resulted in both an increase in the plant's capacity and availability.

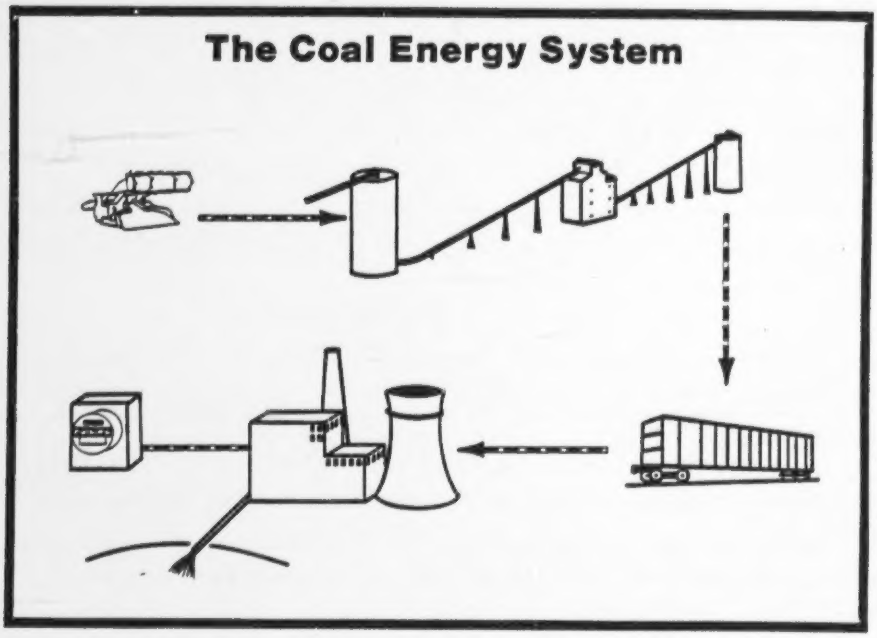
Thus, the increased cost of the fully washed coal was offset by the factor of more units of electricity being generated from the same embedded capital and the cost of a unit of electricity was not affected.

QUESTION 10

Obviously such decisions to wash coal require capital investment on someone's part and require overall economic studies to determine the benefits, do they not?

ANSWER 10

Indeed they do. They require an understanding of what can be referred to as the "Coal Energy System" as shown graphically in Exhibit 5.



The Coal Energy System

Exhibit 5

It requires a recognition of all the components of cost incurred by the user, not only the pithead or cost of the coal at the mine, but all those involved, namely, the integrated coal energy cycle as depicted here. This pictorial representation deals with the electric generating industry which is appropriate since this market accounts for some 83% of all the coal burned in the United States. Based on the WOCOL information already shown in Exhibit 1, this market represents the potential for United States coal, both at home and overseas.

Equally important are the design characteristics of the boiler in which the coal is to be utilized and a recognition of the narrow range of qualities which existing individual boilers can burn and achieve a high level of availability, thereby minimizing the cost of a unit of electricity. In recent years, manufacturers have specifically designed boilers to efficiently accommodate a wider range of coal qualities.

Identifying the physical and chemical characteristics of the coal is vital to minimize the "slagging" and "fouling" in boilers which are the mitigators against high availability.

Coal washing contributes to reduced "slagging" and "fouling" by reducing the amount of ash and providing a consistent product.

This is a complex subject which cannot be dealt with in detail this morning, but to illustrate, I give these self-explanatory nomograms on the following pages which show the benefits of coal washing in achieving these objectives.

At Appendices B, C, and D are further notes from my engineering colleagues on these subjects which might make interesting reading.

In short, the tremendous decrease reported on the charts in the "slagging" and "fouling" characteristics of these coals has been economically achieved by the efficient use of well-proven coal preparation techniques. In each case, the economics of washed coal has successfully related to kwh cost within the "Coal Energy System" approach and has given rise to sulfur dioxide reductions which in practice have had a minimal cost compared with the other alternatives.

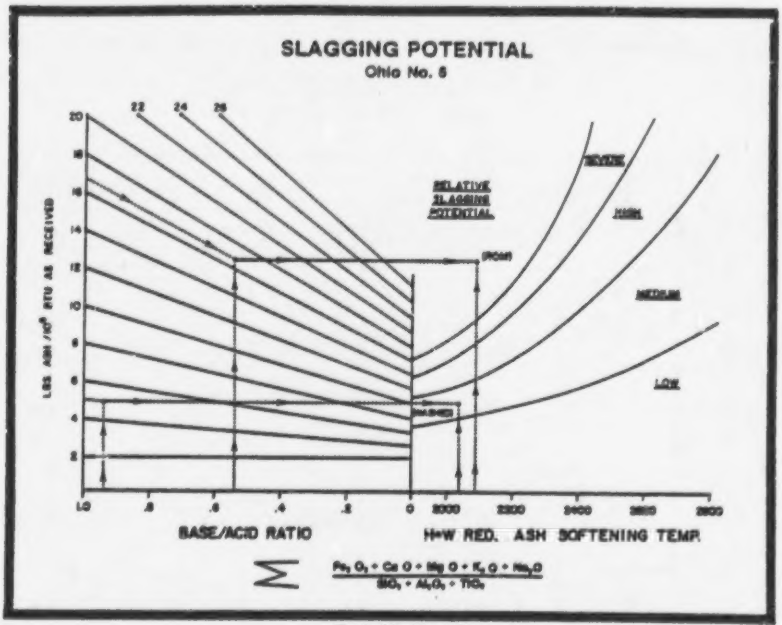


Exhibit 6

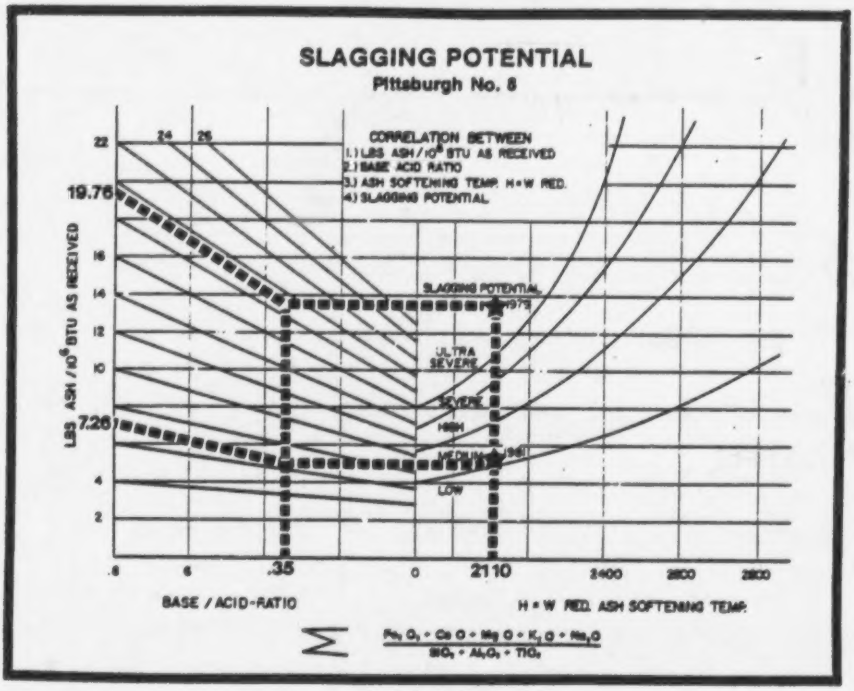


Exhibit 7

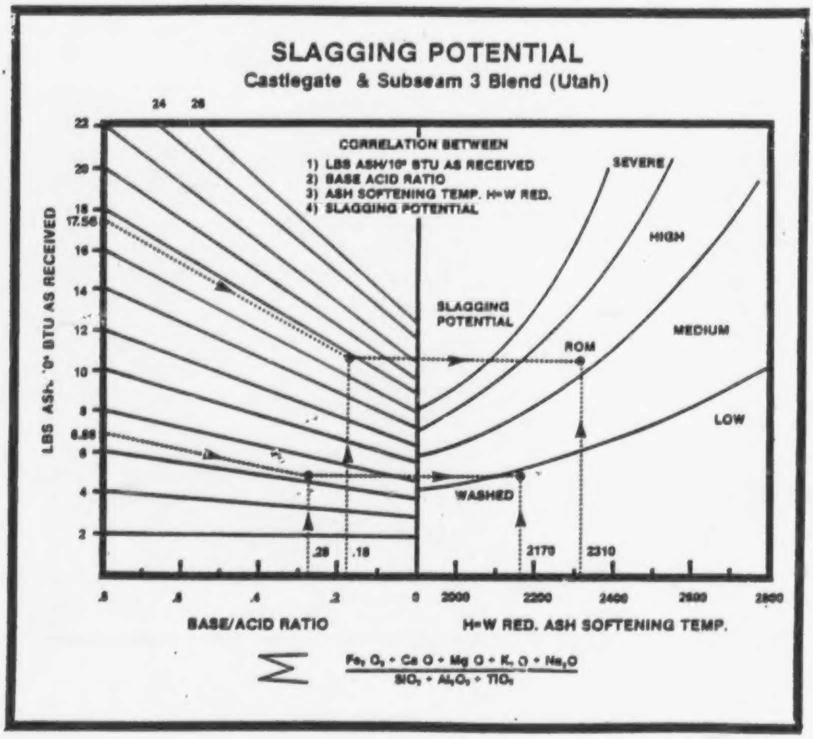


Exhibit 8

QUESTION 11

You appear to believe there are tremendous merits in spending much time and money on the analysis of the "Coal Energy System" for each individual plant. Can you justify it?

ANSWER 11

Charity begins at home. The chart on the following page which contains extracts from the last three AEP Annual Reports, is pertinent. Please remember that about 90% of AEP's generation is from coal.

American Electric Power Company, Inc.
Analysis of Major Operating Expenses

	1980	1981	1982
Operating Expenses			
Fuel*	1.29¢	1.43¢	1.60¢
Maintenance	.22¢	.24¢	.30¢
Depreciation	.25¢	.28¢	.34¢
Taxes	.32¢	.35¢	.46¢
Interest	.39¢	.43¢	.52¢
Total Above	2.47¢	2.73¢	3.22¢
Average KWH Price	3.28¢	3.60¢	4.14¢
Energy Use in Millions of KWH	111,510	113,011	97,535
Cost of Coal Consumed	1.52¢	1.69¢	1.82¢
Operating Expenses			
Fuel*	52.23%	52.39%	49.69%
Maintenance	8.91%	8.80%	9.32%
Depreciation	10.13%	10.26%	10.56%
Taxes	12.96%	12.83%	14.29%
Interest	15.79%	15.76%	16.15%

* Includes all fuel.

In short, since some 50% of all a company's operating expense is fuel, then management's priority is clear.

Additionally, on a national scale the potential for the "Coal Energy System" approach is very appreciable. Why?

There are some 250,000,000 kilowatts of coal-burning electrical capacity in the United States on which the average annual availability appears to be about 66%, whereas, for example, AEP, the largest coal-burning utility, averages over 76%. This has not been achieved without regard to cost since the rates AEP is allowed to charge its customers are either the lowest or near lowest in each of the seven jurisdictions in which it provides service. We do not presume that what AEP does to achieve this higher availability and resulting low cost is necessarily universally applicable, but possibly the policies and philosophy should be studied for application on a broader front.

QUESTION 12

Your graphic explanation of the "Coal Energy System" highlights the importance of transportation. Is there any detailed comment you would wish to make on this subject?

ANSWER 12

The impact of the rapid escalation of transportation charges on delivered coal costs -- and therefore coal utilization, both at home and abroad -- has been debated almost ad nauseam. In view of recent experience, perhaps there is a need to review provisions of the Stagger's Act to determine if it provides for an equitable solution to this problem.

Transportation is a critical cost because it forms a component part of delivered costs -- and transporting coal with high moisture and ash content must be counter productive, particularly when one recognizes that the ash is a waste product which must be disposed of.

The impact of overall transportation costs on export coal is even more critical. Exhibit 9 shows the methodology which has to be the basis of analysis.

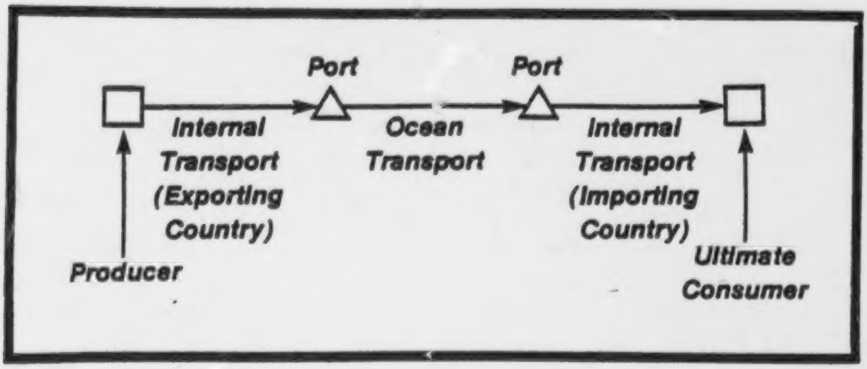

Port
Port
Internal Transport (Exporting Country)
Ocean Transport
Internal Transport (Importing Country)
Producer
Ultimate Consumer

Exhibit 9

In reaching the export markets of the world, we must recognize that a major adverse cost to American competition is caused by very poor coal transportation, or more correctly -- the lack of an integrated transportation system relative to the coal mines themselves, relative to the ports, relative to where the consumers are. In many cases, more than 50% of the delivered cost of coal is comprised of the various transportation cost components.

The competitive position of U.S. coal is heavily affected by transport economics. Proponents of slurry pipelines, offshore islands or superports have argued that unless the nation can export most of its coal in super colliers (150,000 dwt) the U. S. will not become a major coal exporter.

This may be true, but let me bring out some viewpoints, raised by private and public sector economists and in papers presented at "Coal Trans 82," that differ.

> First, there would be minimal savings per ton in shipping costs between using today's ordinary, 65,000-dwt Panamax collier and ships of 90,000 dwt or larger.
>
> Second, employing super-colliers would lessen chances for "backload" cargoes, which, on smaller ships, can reduce the overall voyage or round-trip cost by $5 to $7 a ton under general North Atlantic Charter conditions.
>
> Third, vessels larger than the Panamax collier would require rapid unloading equipment. This would mean outlays at European ports of from $200 million to $400 million each for outreach and overreach unloading equipment.
>
> Fourth, most European ports are limited to Panamax-size vessels; and
>
> Fifth, transshipping coal from larger vessels to smaller raises costs substantially.

The super-port and the super-ship may very well be the path to follow for the future, but the immense capital investments they will require must be linked, for the sake of the investor, to long-term commitments for coal with customer countries. I suggest that we do have at hand the very basics for exports upon which such long-term commitments can be built.

On this subject, for the benefit of current investors or future investors, I would like to make several points and then raise a question:

- If the thesis I have previously presented, namely, that the economics of the end-product user can only be achieved by a selective product;
- that the delivery of selective products does not of necessity lend itself to the use of high capacity boats and terminals which, in turn, require costly dredging, then,
- unless the potential customer is prepared to commit himself to long-term contracts which give reasonable reimbursement for the new investments; then
- should not the United States investor beware of the potential liability and high risk in new port developments which require near capacity utilization before the investment gives a reasonable rate of return?

QUESTION 13

In a previous question you indicated that there was a potential increase for the U.S. coal industry in the industrial market, from 68 million tons in 1979 to some 155 million tons in 1990.

Would you care to elaborate on this?

ANSWER 13

As is usual, it is a mistake to generalize. But I would make two points:

- normal industry steam boilers operate in and around 1500° F. At this temperature, high sulfur coals can have a large part of their sulfur neutralized by the admixture of limestone. Hence, the environmental problem can be more easily and economically handled.

- all feasibility studies of conversion of oil and/or gas industrial steam boilers or new installations show that the capital investment is appreciably higher with coal than with oil and gas. The payback period is therefore longer.

The governments of some countries, certainly the United Kingdom and France, have followed the recommendation of the International Energy Agency (IEA) and arranged for the availability of substantial sums of low interest capital to achieve higher industrial coal usage.

There are some who might argue that this is a form of subsidy, but I suggest there are balances, namely, independence and greater in-state GNP.

Alternatively, a system of preferred tax benefits would achieve the same objective.

In any case, most knowledgeable persons accept that the feasibility studies are favorable over the depreciation life of the boiler plant.

In short, the probable solution to achieving an additional 100-million-ton industrial coal potential in the United States lies with the government and the financiers.

QUESTION 14

In your answers so far, you seem to indicate that the opportunities for the U.S. in the next 10-15 years are based on the integrated planning and use of known technologies. How do you view the potential for new technology?

ANSWER 14

I suggest that all forms of R&D should initially be reviewed for their business potential and, therefore, the view of the businessman is important.

In presenting new technologies for coal to the business community, two major parameters must be made clear. Whatever the superficial merits of coal in its delivered form, it must:

a) over the depreciation life of the asset in which it is burned or utilized, contribute to the competitiveness of the user's product; and
b) do this in an environmentally acceptable manner, taking into account overall economics.

My previous evidence indicates strong justification for coal of consistent quality being fundamental to both these business parameters.

Additionally, the environmental concerns being expressed in the United States in recent years -- the acid rain argument for example -- are of equal or greater concern in many countries to which U.S. coal might be exported.

This subject has been analyzed by a special committee of the CIAB of which I was privileged to be a member. Their report, "Coal Use and the Environment," comprises a two-volume text.

Therefore, the real potential for meaningful R&D from a businessman's standpoint is back to the two parameters. In short, an emphasis preferably on pre-combustion or during combustion desulfurization which will achieve overall economic benefits.

I do not presume to be qualified to address such technologies but I suspect subsequent witnesses will address, among others:

a) fluidized bed combustion;
b) various forms of chemical coal beneficiation; and
c) various forms of electrostatic sulfur and ash removal beneficiation systems.

In the field of oil replacement by coal, a continuation of the R&D on coal/oil and coal/water mixtures, particularly the latter, appear to have major potential, particularly for the reconversion of boilers which were originally designed for burning high-sulfur oil and have some space available for the addition of ash removal facilities.

In either of these cases, a low sulfur content and the lowest possible ash in the coal fraction must be highly desirable.

In short, the potential, first at home and subsequently abroad, is tremendous, but only under the coordinated and integrated terms I have suggested.

QUESTION 15

In your answers you have laid great emphasis both in the U.S. and overseas on the impact environmental decisions will have on the future of coal.

Coal's potential in electric generation in the U.S. and its benefits in terms of energy independence, an improved balance of payments and the stability of its contribution to the GNP of the coal-producing states in the nation are enormous. Bearing these factors in mind, have you done any analysis which would suggest a logical interim action by government which would reduce sulfur dioxide emissions on a reasonable basis pending an outcome of scientific proof of an adverse relationship between SO_2 emissions and environmental damage?

ANSWER 15

Available statistics will show that the electric generation industry has already implemented various schemes, which have in total reduced emissions some 20% below what current regulations demand. The application of comprehensive coal washing has already made a major contribution to the reduction.

The majority of bills presently before the Senate would require massive further reductions with tremendous capital investments which it is estimated would increase electricity costs over the major industrial area of the country by some 50%. None of the bills have a scientific justification.

It is suggested that there is a vital need for a recognition of the further substantial impact that washed coal can have without economic impact on sulfur dioxide reductions to give time to assess whether the irrevocable move to scrubbers is justified.

QUESTION 16

At an early stage in your presentation you applauded the term of reference for this meeting but it would appear in your questions and answers that you have completely disregarded them. Would you care to defend your approach?

ANSWER 16

I can agree with the superficial conclusion implied by the question.

I defend my approach on the basis that unless there is an integrated understanding of the problems from the coal face through to the busbar in the case of the electrical generation industry or, in general, a recognition of the economics of the end product user, the agreed massive potential for coal, both at home and abroad will not be achieved.

One must question whether a reliance on past marketing techniques to achieve this potential will be successful.

In these circumstances, a reliance on past marketing techniques to achieve the potential must have limitations. The best justification for this comment is covered by the question, "What U.S. coal companies have long-term export orders for thermal coal?" To the best of my knowledge, very few, if any.

In short, the increase in export sales which gave rise to the optimism of the 1978-81 period was based on the oil shortage and the U.S. today remains as the "swing market supplier." Its ability to react to demand faster than any other international export supplier is recognized, as is its ability to supply immediate demands without long-term commitments.

I suggest there is no more efficient or highly competitive force in the world than the U.S. coal industry. But in the current world markets, these advantages are being used to its detriment.

QUESTION 17

Are you prepared to make any recommendations for consideration by those who have the power to assist?

ANSWER 17

Yes. I would respectfully submit the following suggestions:

1) The most pressing requirement in the U.S. is a phased economic resolution to the problem of "acid rain" which duly takes into account economic factors and scientifically supported considerations.

2) A recognition by those who control utility revenues, that:
   a) the lowest cost ton of coal does not of necessity produce the lowest unit cost of electricity; and a recognition of
   b) the value of consistent quality coal, of appropriate ash characteristics, in achieving sulfur dioxide reductions, optimizing boiler availability and lowering the cost of a unit of electricity over a period of time.

3) At all times the importance of the economics of the end-product user must be accepted as an ultimate criterion for answers.

4) A recognition that the vast capital expenditures in coal mines, transportation and port facilities constitute a very high risk if not supported by long-term contracts. These investments are hazardous if dependent on a "swing market supplier" situation.

5) That traditional marketing techniques will no longer be successful for thermal coal unless there is an understanding of the overall economics covered by the graphics of the "Coal Energy System" (Exhibit 5) and the transportation infrastructure (Exhibit 9).

In short, in the overall "Coal Energy" approach each marketplace might demand a more selective product to produce the better bottom line for the user's end-product and the transportation requirements might be very different for massive bulk deliveries in 100,000 - 250,000 ton boats.

QUESTION 18

How would you suggest the marketing aspects of these problems might be tackled?

ANSWER 18

If the integrated approach to satisfying the economics of the end-product user is accepted, then there is a need for the forming of consortiums by the energy producers and users who have the experience and proven "know-how" of integrating the technology and economics from the coal face to the end-user.

From this integrated base, coal specifications can be tailored, supplies arranged and associated transportation services incorporated, with each investor getting a fair share of the rewards, taking due account of the investment that each has at risk.

QUESTION 19

Do you believe that such expertise is available in the U.S.?

ANSWER 19

Yes. A number of large electric utility companies have in recent years set up such organizations: the efficiency of each one can be judged on its operations and proven results in this country. Engineering principles and technology do not vary appreciably. Know-how and implementation costs do.

QUESTION 20

What about new technology? Have you any recommendation?

ANSWER 20

There is a great need for support for new technology in terms of priority to:

a) further reduce importation and/or use of oil and natural gas;
b) to reduce sulfur prior to combustion; and
c) to constantly review the time-phased economics of synthetic fuels.

However, getting back to the term of reference of this panel, the business approach to any R&D work should be a priority and, again, charity should begin at home.

I raise the question as to whether it is a good business technique to attempt to sell technology offshore which has not proven beneficial in U.S. economic terms.

QUESTION 21

Have you any further comment?

ANSWER 21

No. I have taken more than my fair share of the time available, but I hope it has been constructive for the oncoming contributors to this panel hearing.

COMPREHENSIVE COAL CLEANING
as an
ENVIRONMENTAL SO_2 CONTROL STRATEGY
for
MUSKINGUM RIVER GENERATING STATION
Beverly, Ohio, USA

Prepared by:

American Electric Power Service Corporation
on behalf of
Ohio Power Company
for the
COAL INDUSTRY ADVISORY BOARD
Environment Task Force
of the
INTERNATIONAL ENERGY AGENCY

AEP
FUEL SUPPLY

DRAFT 4/5/82

COAL INDUSTRY ADVISORY BOARD
ENVIRONMENT TASK FORCE

Case Study

Respondent:

American Electric Power Service Corporation
on behalf of
Ohio Power Company

Muskingum River Generating Station
Beverly, Ohio, U.S.A.

A coal-fired generating station consisting of five (5) units totaling 1,425 megawatts with the first four units ranging in age from 25 to 30 years and the fifth unit 14 years. This is a minemouth facility located in southeast Ohio, burning on the order of 3,300,000 annual short tons of coal.

Environmental compliance strategy has been to meet U.S. Federal and State sulfur dioxide emission standards by comprehensively washing the local, high sulfur coal which comes from the Central Ohio Coal Company (a wholly-owned subsidiary of Ohio Power Company).

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DRAFT 4/5/82

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DRAFT 4/5/82

EXECUTIVE SUMMARY

The Muskingum River Generating Station is located in a sparsely-populated region of southeastern Ohio. It has been determined by the various environmental regulatory authorities that sulfur dioxide ambient air quality standards could be maintained in this region without the severe emission restrictions placed on stationary sources in highly populated and industrial regions.

Generating stations in this region have traditionally burned the higher sulfur Ohio coals which, for many years, have yielded sulfur dioxide emissions in excess of 12 lbs/MBTU. Through modeling and real-time monitoring, it has been determined that SO_2 emission levels in the range of from 5 lbs/MBTU to 10 lbs/MBTU could be accepted for meeting ambient air quality standards.

The electric utilities, therefore could meet such emission levels by acquiring a fully-washed local coal without having to resort to the extraordinary expense of scrubbers or switching to low sulfur fuel supplies.

This case study reviews the introduction of fully-washed coal to the Muskingum River Generating Station and the benefits which accrue. In summary:

1) The SO_2 emissions resulting from burning the fully-washed coal are some 38 percent less than burning the same coal in the raw state or 20 percent from a partially-washed state. With an annual burn of 3,300,000 clean tons, this achieves a substantial reduction in atmospheric loadings, from more than 400,000 tons of SO_2 per year by burning ROM coal to 256,000 tons from washed coal.

2) The cost impact going from partially-washed to fully-washed coal has been minimal, only 4 cents per million BTUs in constant dollars. This compares to the cost of scrubbers or fuel switching which would equate to from $15 to $18 per short ton coal equivalent.

3) The higher, more consistent quality of the washed coal yields increased efficiencies and availabilities at the power station. Since fully-washed coal was introduced the Muskingum River station has been able to increase its capacity rating by 50 megawatts or 3.6 percent. The value of this additional generation to the System, based upon replacement costs, is $13,750,000 per year.

4) Current results indicate that plant availability will increase a minimum of 5 percentage points. This increase would make nearly 625,000 additional megawatthours available which would yield a pre-tax income, at the busbar of $6,000,000 annually.

5) Increased availability and fewer forced outages result in lower maintenance cost.

Coal washing provides economic benefits which minimize the cost of meeting environmental regulations, reduce consumer cost and continue to provide economic support for the higher-sulfur coal region of Ohio.

DRAFT 4/5/82

PLANT DESCRIPTION

Muskingum River Generating Station, Beverly, Ohio, USA

Five coal-fired, steam generating units.

#1 — 205 megawatts
#2 — 205 megawatts
#3 -- 215 megawatts
#4 — 215 megawatts
#5 — 585 megawatts
1,425 megawatts

The facility is owned by Ohio Power Company, a wholly-owned subsidiary of the American Electric Power Company, Inc., and operated by Ohio Power Company.

Total output is used for electric power with an average annual output of 7,581,000 mkwh/yr.

Efficiency: 3412.14 + 9630BTU/kwhr = 35.43%

Heat Rate: 9630 BTU/kwhr = 10161 KJ/kwh

PLANT FACILITIES

Boiler type and description:

2 units, pulverized coal, wet bottom
2 units, cyclone-fired, wet bottom
1 unit, opposed fired, dry bottom

Steam system:

4 units, subcritical
1 unit, supercritical
4 units, operating steam pressure and temperature:

P = 2075 psi
T = 1050/1050°F

1 unit, operating steam pressure and temperature:

P = 3500 psi
T = 1000/1025/1050°F

Initial commercial operation:

Unit 1 — 1953
Unit 2 — 1954
Unit 3 — 1957
Unit 4 — 1958
Unit 5 -- 1968

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Projected initial life of boiler -- 33 years
(no changes as a result of modification)

Sulfur dioxide control at plant:
(none)

Particulate control at plant:

Cold-side electrostatic precipitators with the degree of control required to meet environmental regulations.

SULFUR DIOXIDE EMISSION REGULATORY STATUS

No final sulfur dioxide emission standards have been promulgated for the Muskingum River Generating Station. (see regulatory history at Appendix "A").

The controlling regulatory agencies are the Ohio Environmental Protection Agency and the U. S. Environmental Protection Agency.

Over the past ten years, various sulfur dioxide emission limitations have been proposed by the regulatory agencies or the Company which would meet the ambient air quality requirements of The Clean Air Act. Both the Ohio and U. S. Environmental Protection Agencies have given indications that an emission standard of 8.6 lbs. SO_2/MBTU will be acceptable to satisfy the primary ambient air quality standards. The Company anticipates acceptance of that standard in the near future.

SULFUR DIOXIDE EMISSION COMPLIANCE APPROACH

The Company's approach for meeting the anticipated sulfur dioxide emission standards is to provide a fully-washed coal from its Central Ohio Coal Company mine. Washing the coal will affect a 38 percent reduction in SO_2 emissions compared to run-of-mine coal and a 20 percent reduction from the previously, partially-washed product meeting an 8.6 lbs/SO_2/MBTU limit..

FUELS CHARACTERIZATION

General Comment: The Muskingum River Generating Station was sited near Beverly, Ohio adjacent to some 130,000 acres of coal-bearing lands owned by the Company and operated by Central Ohio Coal Company. The concept of mine-mouth generation has, over the years, proven to be a highly economical source of fuel supply for electric generation. Transportation costs are kept at a minimum through the use of a mine mouth to generating plant conveyor belt delivery system. The company-owned supply also provides a high degree of security and dependability.

The Central Ohio Coal Company reserves cover some 130,000 acres of land. These reserves were developed in conjunction with the construction of the Muskingum River Station. Over 85,000,000 tons of coal have been mined with 86,000,000 tons of recoverable reserves still in place. With an annual burn requirement of 3.3 million clean tons per year at Muskingum River Station, there are sufficient reserves to last nearly 25 years, more than enough to satisfy the requirements for the remaining life of the generating station.

Substantial investments have been made in developing this coal property, providing employment for nearly 900 people in east-central Ohio. The full utilization of these assets is critical to the economic health of the Company and local communities.

The coal, properly beneficiated, is of the appropriate quality to meet the operating requirements of the generating station. The following table shows the minimum and maximum qualities which have been experienced and can be expected using the coal in its raw state, partially washed (coarse coal cleaning only), and fully washed.

	Run of Mine	Partially Washed	Fully Washed
BTUs	8400-10000	9600-10800	11100-11500
Ash%	20-32	16-24	11-14
Sulfur%	5.0-10.0	4.5-6.0	4.3-4.7
Moisture%	4.0-7.0	5.0-7.2	7.8-8.6
Yield%	100-100	90-96	83-87
SO_2 (#/MBTU)	10.0-23.8	8.3-12.5	7.5-8.5

The key benefit, in addition to the higher quality of the fully-washed coal, is the elimination of the wide fluctuations of ash, sulfur and other coal properties experienced from run-of-mine coal. Many generating plant problems can be either reduced or totally eliminated by burning a consistent quality fuel.

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Pre-modification: Bituminous coal, Ohio, District 04
Partially washed product with +1¼ inch processed in a jig and -1¼ inch to 0 going to clean coal.

Product specification (yearly average) as received:

S	5.03%	
Ash	19.85%	
BTUs	10,348/lb.	
T_{id}	reducing	2010°F 1085°C
	oxidizing	2450°F 1329°C
Moisture	6.49%	
SO_2	9.73 lbs/MBTU (range — 8.3-12.5)	

Firing rate:
Maximum continuous rating:
$13,071 \times 10^6$ BTU/hr.

Average annual burn:
3,307,000 short tons

Post-modification: (same supply source as pre-modification)

Fully Washed product with:
+ 3/4 inch — water only jig
3/4 inch to 28 mesh — heavy media cyclones
28 mesh to 0 — froth flotation

Product specification (yearly average) as received:

S	4.44%
Ash	12.20%
BTUs	11,372
T_{id}	(same as pre-modification)
Moisture	8.56
SO_2	7.81 lbs/MBTU (range — 7.5-8.5)

Firing rate:
Maximum continuous rating:
$13,071 \times 10^6$ BTU/hr.

Average annual burn:
3,229,000 short tons

SULFUR DIOXIDE EMISSIONS

Pre-modification:

kg/kJ — 4.2×10^{-6}
t(m)/yr. — 300,000 lbs.
SO_2/MBTU — 9.73 yearly average (range — 8.3-12.5)

Post-modification:

kg/kJ -- 3.3×10^{-6}
t(m)/yr. -- 256,000
lbs. SO_2/MBTU -- 7.81 yearly average (range -- 7.5-8.5)

IMPLEMENTATION PLAN AND WASHPLANT DESCRIPTION

By comprehensively cleaning all the coal, using the latest and most efficient frothing methods and heavy media cyclones, the product produced is now meeting, on a consistent basis, an SO_2 standard of 8.6 lbs/MBTU.

The Company has invested approximately $18,000,000 in upgrading its coal washing facility at Central Ohio Coal Company. The incremental cost of thoroughly washing this coal, achieving an 86 percent yield, is $9.3 million on an annual basis in 1981 dollars or approximately $3 per clean ton.

Pre-modification coal washing:

Prior to modification, only the 5" x 5/8" (125 x 16mm) coal was washed. The 5/8" x 0 (16 x 0mm) raw coal bypassed the jig and was sent directly to the clean coal belt.

The coarse coal was cleaned in a jig and produced an 86% weight recovery in clean product.

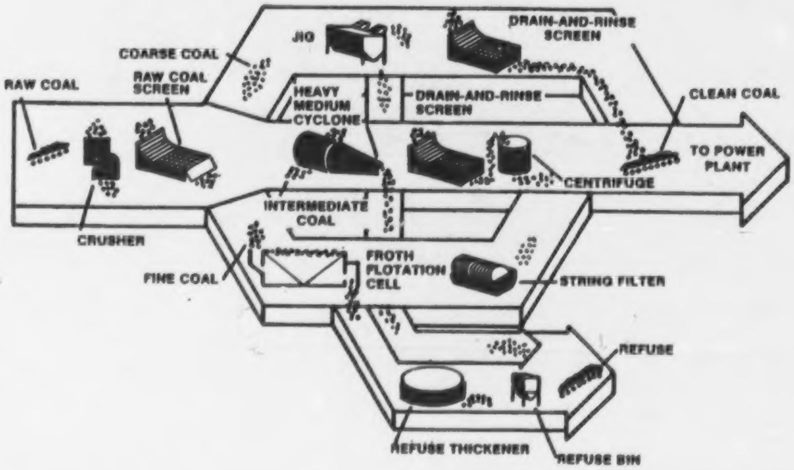
The percentage of washed coal in the total power station feed was on the order of 20 percent.

Post-modification coal washing:

Extensions to the existing coal washing facilities provided for washing all size fractions. The project was completed and operational in early 1980. In addition to new coal washing circuits, the existing jigs were rehabilitated and fitted with fully automatic bed level controls for cleaning the 5" x 3/4" (125 x 20mm) coarse coal.

Four 30" (762mm) diameter heavy media cyclones and ancillary screening equipment were installed to clean all 3/4" x 28 mesh (20 x 0.5mm) intermediate coal. Both the jig and the heavy media cyclones are operated at a 1.70 effective dp.

Muskingum Simplified Flow Sheet



Fine coal cleaning facilities for the 28 mesh by 0 (0.5 x 0 mm) size consist include two banks of six 500 cubic feet (14.16m^3) cell to cell flotation machines and four 600 square feet (55.75m^2)clean coal dewatering filters.

Quality comparison:

Parameter	Pre-modification (1977)	Post-modification (1981)
Ash	19.85% (16-24%)	12.20% (11-14%)
Sulfur	5.03% (4.5-6.0%)	4.44% (4.3-4.7%)
Moisture	6.49% (5.0-7.2%)	8.56 (7.8-8.6%)
BTUs	10,348 (9,600-10,800)	11,372 (11,100-11,500)
SO$_2$ (#/MBTU)	9.73 (8.3-12.5)	7.81 (7.5-8.5)

NOTE: ( ) Indicate maximum and minimum ranges.

Pre-modification solid waste disposal:

Waste disposal consisted of land filling the 5" x 5/8" (125 x 16mm) coarse reject from the jig. The 28 mesh x 0 (0.5 x 0mm) fines were collected during water clarification and pumped to ponds for consolidation. The ponds were cleaned by excavation with the solids being trucked to the coarse reject disposal area, compacted and prepared for reclamation and revegetation.

DRAFT 4/5/82

Post-modification solid waste disposal:

The coarse reject, 5" x 3/4" (125 x 20mm) is dewatered on vibrating screens and combined with the 3/4" x 28 mesh (20 x 0.5mm) intermediate reject which is dewatered in basket centrifuges. This material is used as embankment fill for the slurry impoundment which receives the thickened 28 mesh x 0 (0.5 x 0mm) flotation tailings. Clarified water is returned from the impoundment and re-used in the washing process thus creating essentially a closed circuit system.

Runoff from the embankment face and the washplant coal storage area is collected and treated in a fully automated treatment facility prior to re-use in the plant or discharge through a permitted outfall.

PROJECT ECONOMICS

In evaluating sulfur dioxide compliance options for the Muskingum River Generating Station, the Company reviewed: the installation of scrubbers, fuel switching to low-sulfur coals and comprehensively washing the existing coal supply.

- SO_2 Scrubbers

  Scrubbers involve a capital investment on the order of $150 per kilowatt of installed capacity, or about $214,000,000 for this facility. Considering the current high cost of capital, servicing that debt would be over $21,000,000 per year. The annual costs of owning and operating scrubbers for the Muskingum River Station would total approximately $45,000,000 per year which equates to some $15 per ton coal equivalent. For a plant with four of its five units over 20 years old, this was not a viable option.

- Fuel Switching

  Acquiring a low sulfur coal as a blender would require an estimated 500,000 tons per year. The cost premium of this coal, FOB mine, would be a minimum of $10 per ton and transportation would add an additional $10 to $15 per ton if rail transportation was available, which it is not. This would be an annual cost penalty of $10,000,000 to $12,000,000. The actual increased annual costs would be even higher, considering that transportation facilities would need to be capitalized. This option would also be cost prohibitive.

- Washed Coal

  Coal washing is a much lower cost SO_2 compliance strategy, and in fact provides economic returns upon the increased investment in washplant facilities.

These returns can be categorized as follows:

1) increased heat content (BTU level) of the "as received" product;

2) improvements in boiler/plant capacity;

3) improvements in boiler/plant availability; and

4) reduced boiler operating and maintenance costs.

The Company made the following assumptions in evaluating the economic feasibility of washing the local coals for the Muskingum River Generating Station:

1) The annual incremental costs of fully washing the coal would be on the order of $9,200,000 (1981 dollars) or about $3 per clean ton.

2) The BTU content of the coal on an "as received" basis would rise from 10,300 BTUs to 11,300 BTUs.

3) The introduction of fully-washed coal, plus modifications to the boilers, would enable the plant to increase its capacity rating by a minimum of 50 megawatts and, by burning fully-washed coal, maintain that increased rating over the economic life of the plant.

4) Reductions in coal-related outages would be reduced, increasing effective availability from the pre-modification period level of 75 percent to something over 80 percent.

5) Reductions in maintenance costs, as a companion benefit to "4", above, and a stretching out of planned maintenance outages.

The plant has been operating with a fully-washed coal for just under two years. Whilst it is too early to quantify and prove all the assumptions made above, the following comments can be made:

1) The impact upon the cost of fuel in ¢/MBTU delivered, as a result of fully washing the coal for the Muskingum River Station, has been minimal.

The comparison of delivered costs, on a cents per million BTU basis, for the last two years prior to the implementation of full coal washing and two years since is as follows:

Cost per million BTUs recast into 1981 dollars*

Pre-modification	(1978	148.26¢
	(1979	147.87¢
Post-modification	(1980	148.47¢
	(1981	152.22¢

The four cents per million BTU increase, is less than a 3 percent increase based upon constant 1981 dollars.

2) Unit #5 has been upgraded from 535 megawatts to 585 megawatts as a result of refinements made in the furnace wingwalls and the introduction of a fully washed coal product.

The value of this additional 50 megawatts of capacity to the System, based upon replacement cost, is as follows:

50mw @ $1,100 per kw = $55,000,000 capital cost

Annual owning cost (interest and amortization) at 25 percent of capital cost = $13,750,000 per year.

3) The projected increase of 5 percent in availability is based upon the Company's experience with other coal-fired generating stations. An American Electric Power study comparing the performance of two identical 800 mw units, one burning the appropriate coal and the other inferior coal, demonstrates that availability can vary by as much as 12 percentage points. A brief discussion of that study is included as Appendix "B".

An increase in availability of the Muskingum River Generating Station of 5 percentage points (from 75% to 80%), a conservative estimate, would yield the following results:

Plant Capacity		Availability Increase		Hours in year		Increased Annual Mwhrs
1425 mw	x	.05	x	8760	=	624,150

Pre-tax income value of $10 per mwhr** x 6,241,500 mwhrs = $6,241,500

---

*The U. S. Consumer Price Index was used to inflate previous year dollars into 1981 dollars.

** Pre-tax income value of energy for resale at the busbar for the AEP System is 10 mills per kwhr or $10 per mwhr.

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The AEP System has traditionally been a major seller of electric energy and, under normal economic conditions, is in a position to sell virtually all its available generation. In such circumstances, a 5 percentage-point increase in the availability of the Muskingum River station would yield pre-tax income of approximately $6,000,000 as detailed above.

APPENDIX "A"

HISTORY AND STATUS

MUSKINGUM RIVER SO_2 EMISSION LIMITATIONS

On January 15, 1972, the former Ohio Air Pollution Control Board promulgated a uniform statewide SO_2 emission limitation of 1 lb/MBTU for all large boilers. The presumed method of compliance was conversion from coal to oil. Subsequent U. S. EPA approval of the Ohio SIP was set aside by the U. S. Court of Appeals for the Sixth Circuit in Buckeye Power, Inc. vs. EPA, 525 F.2d 80 (6th Cir. 1973). After inconclusive proposals of various different SO_2 emission limitations by Ohio EPA (with pressure from U. S. EPA to relax SO_2 limits under its "Clean Fuels Policy" following the Arab oil embargo of 1973, to free up scarce supplies of low sulfur fuels for use in urban areas), U. S. EPA on November 10, 1975, proposed an SO_2 emission limitation of 2.4 lbs/MBTU for Muskingum River (40 Fed. Reg. 52413). On August 27, 1976, U. S. EPA promulgated a final SO_2 emission limitation for Muskingum River of 6.48 lbs/MBTU (41 Fed. Reg. 36336). This limitation was subsequently remanded to the Agency by the Sixth Circuit in Cincinnati Gas & Electric Co. vs. EPA, 578 F.2d 660 (1978). The Court held (578 F.2d at 663-4):

> "On this present record, we concluded that United States EPA's employment of the Class A assumption in determining pollution dispersion under "least stable" wind conditions in rural areas and areas of complex terrain is not a rational decision and is arbitrary and capricious."

On June 19, 1980, U. S. EPA responded to the Sixth Circuit's remand by adhering to its original Class A assumption (45 Fed. Reg. 41501). On November 7, 1980, U. S. EPA promulgated a final rule reinstating the 6.48 lbs/SO_2/MBTU emission limitation and restarting a 122-week compliance schedule to run retroactively from June 19, 1980. In December, 1980, the State of Pennsylvania filed a notice of appeal in the Sixth Circuit protesting the length of the compliance schedules for Muskingum River Plant as restated in U. S. EPA's November, 1980, notice.

On September 23, 1981, Company representatives met with the U. S. EPA to present a new SO_2 control strategy of meeting an emission standard of 8.6 lbs/SO_2/MBTU using the comprehensively-washed coal from its adjacent Central Ohio Coal Company mine. At the present time (March 1982) the U. S. EPA has given indications that it will be receptive to the 8.6 lbs as a primary standard. In addition, it appears probable that a more stringent secondary standard could be promulgated at 7.6 lbs/SO_2/MBTU with the time frame for compliance being either 1988 or 1989.

On August 30, 1979, Ohio EPA promulgated a 9.52 lbs/SO_2/MBTU emission limitation for Muskingum River which was forwarded to the U. S. EPA which was later disapproved. On January 6, 1982, the Ohio EPA proposed an 8.6 lbs/SO_2/MBTU primary and secondary standard which, following a public hearing on February 25, 1982, was adopted and forwarded to the U. S. EPA on March 16, 1982.

APPENDIX "A"

Action is yet to be taken on either the Ohio EPA revised submission or the Company's revised emission control strategy, which also established an 8.6 lbs/SO_2/MBTU standard.

APPENDIX B

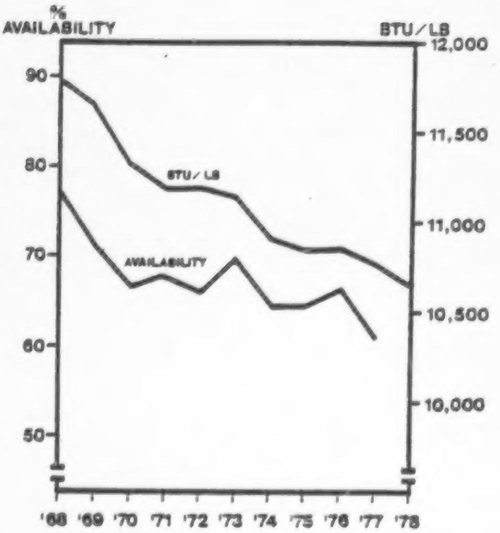
Excerpt from:

THE OUTLOOK FOR STEAM COAL AS USED BY ELECTRIC UTILITIES

by
Gerald Blackmore
Executive Vice President - Fuel Supply
American Electric Power Service Corporation

presented at

American Mining Congress
1980 Mining Convention
September 21 - 24
San Francisco



U.S.
Generating Unit
Availability
vs
Average BTU/lb
1968-1978

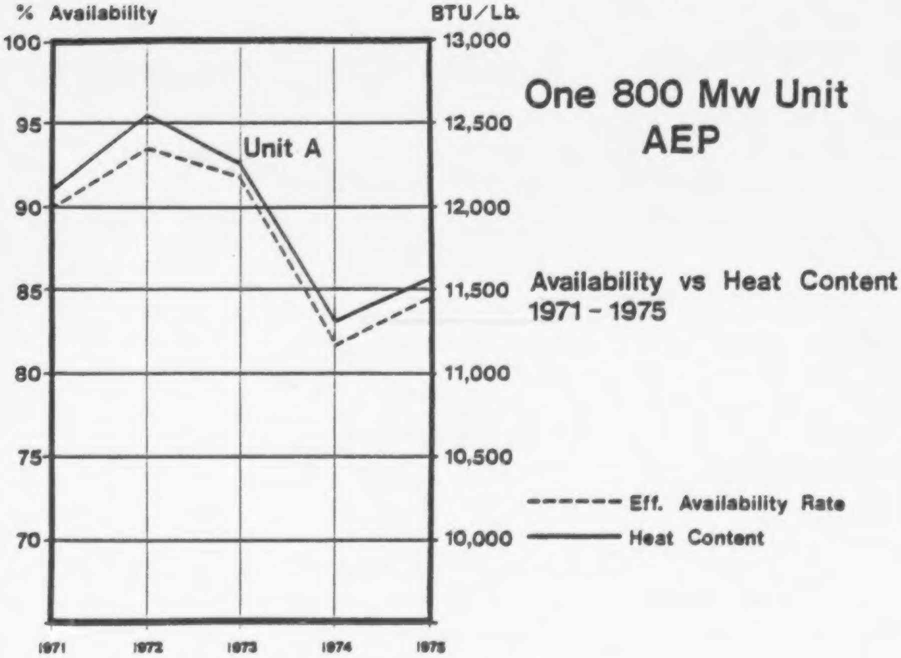
SOURCE: U.S. Dept. of Energy
Edison Electric Institute

Illustration #7

The question must be raised as to the effect of coal quality on plant availability when, at the same time that availability has dropped, the average BTU level of the coal delivered has also dropped from about 11,750 BTUs down to some 10,600 BTUs. The drop is very substantial having taken into account the effect of the increasing production of low BTU Powder River Basin coal.

As an example of the national trend, we might look at Illustration 8 which applies to an 800-megawatt unit on the AEP System. You see here that the availability of the unit has very closely paralleled the BTU content of the coal.

Further insight into the problem can be gained from Illustration 9. This is from a study which compared two units of the same size, design and age. Again, you see a relationship between BTU content and unit availability. However, upon closer examination, you see that BTUs were not the only differences in the two coals. Unit B was fed a coal which, generally, was of inferior quality.

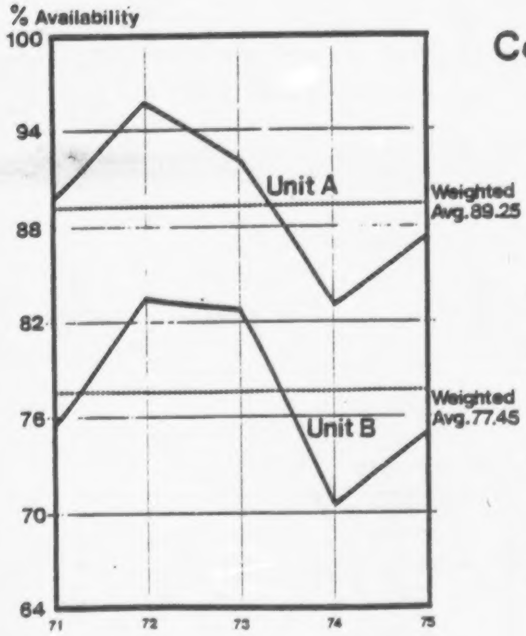


One 800 Mw Unit
AEP

Availability vs Heat Content
1971 - 1975

Illustration 8

Coal - Related Outages
800 Mw Units



Unit A vs Unit B
1971 - 1975

	Unit A	Unit B
Ash +Sulfur	15.2%	19.7%
Heat Index	11,810 BTU/Lb.	11,460 BTU/Lb.
Slagging Index	Low to Medium	Very High
AshFusion Temperature	More Than 2700°F	Less Than 2500°F

Illustration 9

One must recognize that the tremendous difference in availability cannot be attributed realistically to the BTU differential alone.

One of the key factors in keeping the boiler furnaces operating is the ash-fusion temperature. This, by the way, is related to BTUs in the sense that lower BTUs with its correspondingly higher ash tends to aggravate problems associated with marginal ash-fusion temperature coal.

During the past year, we have had to come to some hard decisions as a result of persistent slagging by low ash-fusion coals. At one plant, we had been receiving over a period of years, coal from two mines at very reasonable prices. But the two units at that plant had been running at some 140 megawatts below their rated capacities due to the problems associated with the low ash-fusion coal.

Soot blowers were in use around the clock instead of only an hour or two per shift. An analysis was made to see if a modification of the boilers could be made to recover the lost capacity but the manufacturer would give no guarantees.

With the increased cost of maintenance and higher capital cost of providing replacement power, through new construction, for the lost megawatts, it became essential that something be done.

The only viable alternative was to change the coal supply and put into the boiler a quality of coal that would substantially reduce the slagging, and reduced loadings of these two units.

In short, the logical solutions to improving availability on existing plants must arise from taking the sound, commercially prudent approach of feeding each boiler with that grade and quality coal which will permit the highest possible unit availability.

Indeed, this means that electric utilities, many of which have for years prided themselves on buying cheap coal, will have to accept that the cheapest electricity is not of necessity produced from the cheapest coal.

It must be remembered, as pointed out earlier, that an electric utility's prime responsibility is to provide the lowest possible price per kilowatthour to its customers. In today's economics, this does not necessarily mean fueling the boilers with the cheapest coal.

THE AMERICAN ELECTRIC POWER SYSTEM
AND
COAL-FIRED GENERATION

INTRODUCTION

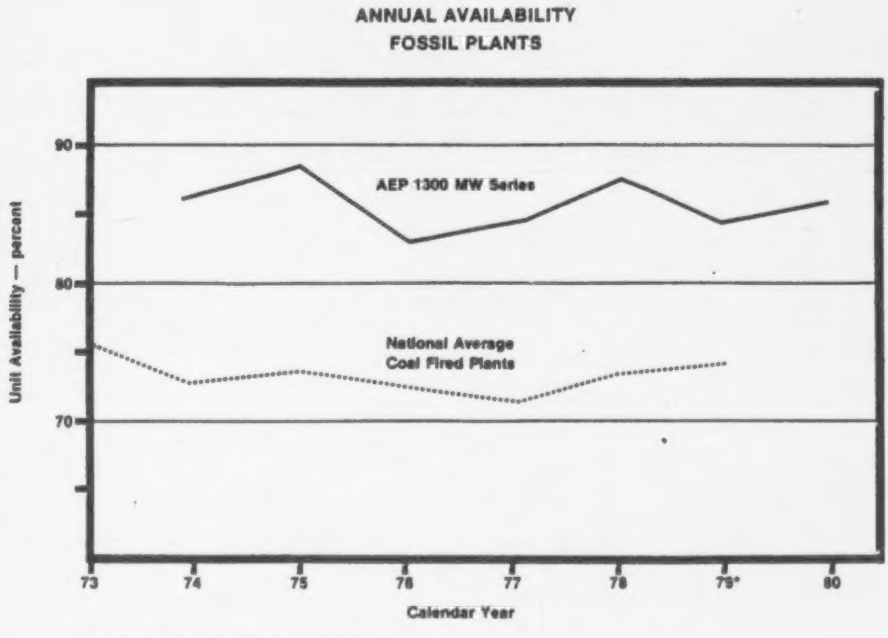
Power generating equipment availability and power plant productivity is a popular subject these days and relates to our nation's overall energy situation. At the Federal level the Department of Energy has focused considerable attention to this subject. The State regulatory commissions are vitally concerned with availability and productivity and its impact on production costs and the timing of additional generating capacity. Needless to say, the electric utility industry is also vitally interested in this subject as it is one of the fundamental keys to our success both in serving our customers and from a financial standpoint.

The American Electric Power System has a history of achieving and maintaining high levels of generating plant availability and performance. Discussed here is what our management philosophy has been on this subject and a brief description of our ongoing programs for achieving high levels of power plant performance.

Our power plant performance objectives and operating record reflect the philosophy and attitude of the Chief Executive Officer of the Company and the Office of the Chairman. The policy of high technical competency in the design and operation of the AEP System power plants goes back some forty years or more. It has been our belief that success is achieved through maintaining, within the Company organization, the engineering skills and resources to design, operate and maintain all the generating facilities on the AEP System. Historically, the AEP Service Corporation has provided this capability. The Service Corporation engineering organization develops the conceptual design, produces the detail design, monitors construction, participates in the start-up and follows and solves any operating problems during the life of the plant. The responsibility, attitudes, experience, and productivity of our engineering organization are quite different as compared to the consulting engineering organizations that provide this service to other utilities.

Some forty years ago we began designing and building series of identical units to take advantage of current technology and the benefits that are derived in availability and costs by duplicating design. Since the early 1940s we have installed eight different series of coal-fired units ranging in number and size, starting in 1941 with three 90

MW units up to the present 1300 MW units, of which four are in service and two more are under construction. The operating record of these large 1300 MW units is excellent. Figure #1 shows the availability record of these units through 1980.



* NERC data through 2nd quarter 1979

Figure #1

Equally important as the design are the day-to-day programs and attention given to maintaining unit availability and plant performance. The Senior Vice President -

Operations, reporting directly to the Office of the Chairman, is responsible for the operation and maintenance of the System power plants. With this centralized management control, all operational planning, utilization of resources, technical support and cost monitoring are carried out on an integrated system basis. Reporting to the Senior Vice President - Operations are the System Operation Department, Plant Engineering Division, Plant Maintenance Division, and the plant managers with respect to operation and maintenance of their plants. The System Operation Department is responsible for the loading of the units and dispatching of power in the system, and with out interconnections . The Plant Engineering Division provides technical support to the plants, and the Plant Maintenance Division provides planning and resource support for the maintenance activities in all the System plants.

These groups work directly with the power plant managers and staff on a day-to-day basis with the overall objective of maintaining good unit availability on a cost-effective basis.

Availability and Efficiency Records

The American Electric Power System has historically been in the forefront in the design, construction, and operation of power plants having high reliability and efficiency. This is the result of having developed the in-house design and service engineering expertise to promote a continuous improvement in power plant productivity.

Figure #2 shows the average operating availability (1) of AEP fossil-fired power plants versus the national average for coal-fired plants. The AEP plant average operating availability over the past ten years has been six to ten percentage points better than the national average. The AEP

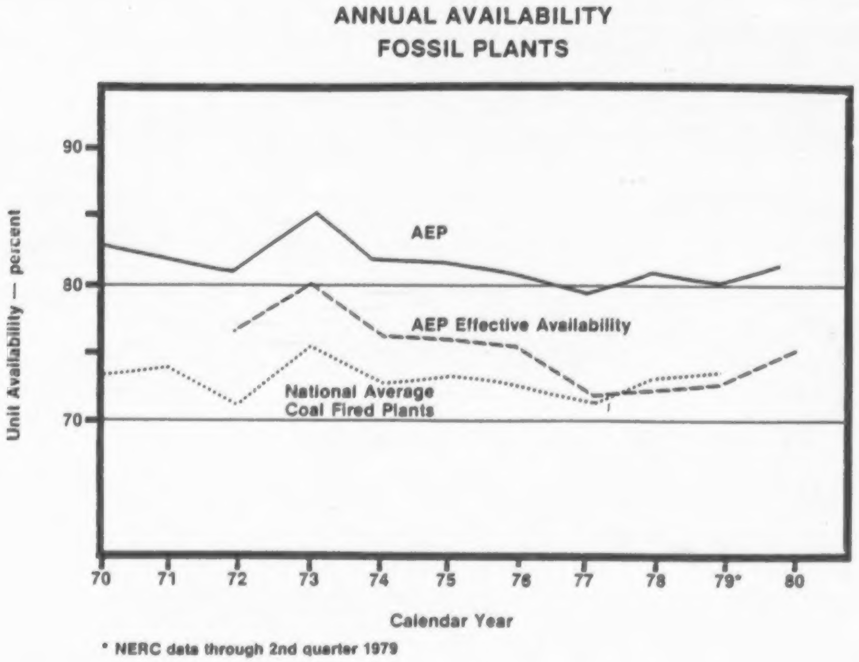


Figure #2

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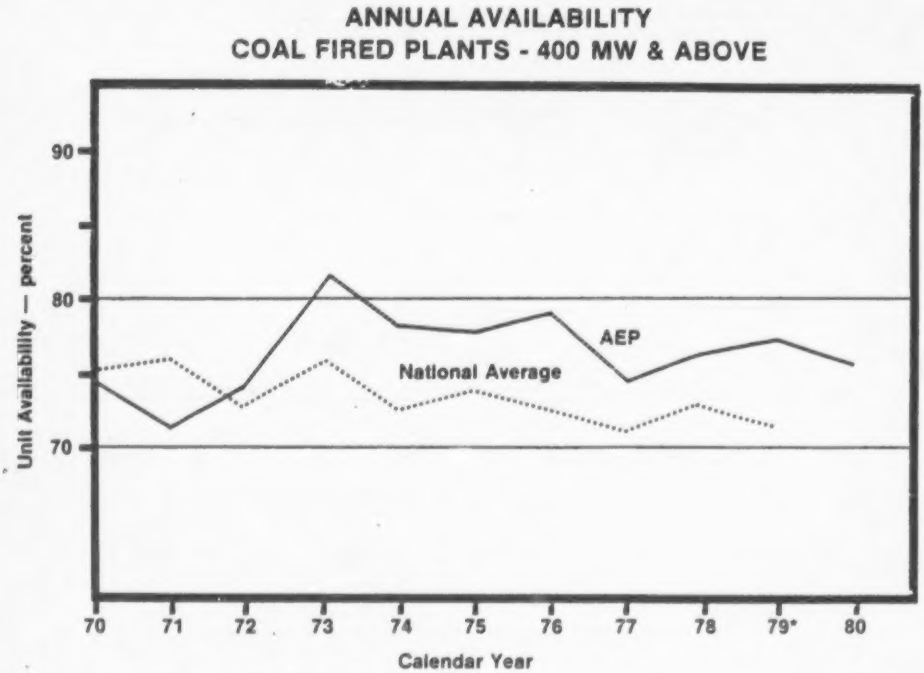
(1) Operating Availability = (Available Service Hours + Reserve Shutdown) ÷ Period Hours

fossil units have averaged better than 80% operating availability over the past ten years. The graph also shows that the effective availability,(2) the true measure of productivity, was at or above the operating availability for the national coal-fired plant average.

Figure #3 illustrates yearly operating availability values for AEP and EEI coal-fired units larger than 400 MW. All of AEP's supercritical units, except Philo Unit 6, are


ANNUAL AVAILABILITY
COAL FIRED PLANTS - 400 MW & ABOVE

* NERC data through 2nd quarter 1979

Figure #3

---

(2) Effective Availability = Available Hours - (Effective Forced Hours + Effective Scheduled Hours) ÷ Period

included in this plot. The AEP units have generally been better than the EEI average. AEP's large units have averaged approximately 77.5% availability over the past ten years.

The American Electric Power System has also taken great strides in designing power plants that produce electricity in the most efficient manner possible. This measure of efficiency is best indicated by the parameter known as heat rate. (3) Figure #4 shows this comparison most vividly.

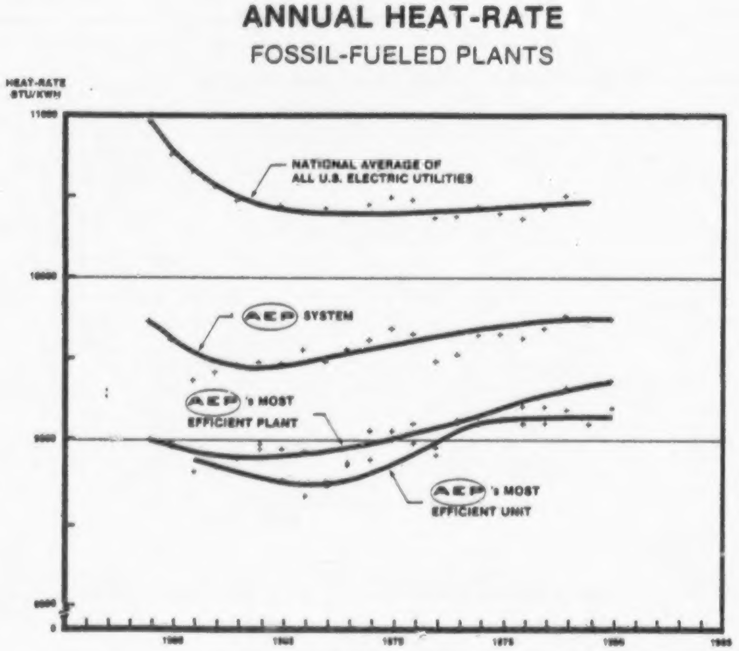

ANNUAL HEAT-RATE
FOSSIL-FUELED PLANTS

Figure #4

---

(3) Heat Rate = Heat Input from Fuel in BTUs ÷ Net Unit Generation Produced in Kilowatthours

AEP has consistently been rated among the top utilities as operating the most efficient units in the United States and has recorded heat rates below 10,000 BTU/kilowatthour for the past twenty (20) years. Most recently the addition of more environmental control equipment has produced a marked increase in heat rate (less efficient) for AEP, as well as for all coal-fired plants throughout the United States. But this trend will produce still further incentives for AEP to design power plants with advanced technology to insure that it remains one of the most efficient power systems in the nation.

Coal Quality

The greatest causes of unit unavailability and deteriorating heat rates are boiler related malfunctions which are the effect of quality of the fuel burned. Fuel quality is a complex relationship that must consider the heating value (BTU per pound) of the coal, as well as the amounts and chemical nature of the ash, sulfur, and moisture that are present in the fuel. All of these parameters interact to affect the productivity of the generating unit. A considerable decline in the heating value of the coal burned within the AEP System began to occur in the 1960s and continued into the mid 1970s. Much of this deterioration is due to the coal industry's move to mechanized mining to enhance production capabilities. Beginning in 1976, AEP initiated a strong pursuit to improve coal quality with the knowledge that improvements in generating unit productivity would result.

FUEL QUALITY AND ITS EFFECT ON THE OPERATION AND MAINTENANCE OF UTILITY FIRED STEAM GENERATORS

FUEL QUALITY AND ITS EFFECT ON THE OPERATION AND MAINTENANCE OF UTILITY FIRED STEAM GENERATORS

PART 1
STEAM GENERATOR DESCRIPTION

TEMPERATURE PROFILE
A. Steam/Water Flow Path
B. Air/Gas Flow Path

DESIGN
A. Furnace Definitions
B. Unit Design Parameters

PART 2
COAL ANALYSIS

PRICE RIVER COAL ENGINEERING FUEL SPECIFICATIONS

PART 3
ENGINEERING APPLICATIONS

APPLICATION ANALYSIS
A. Data Summary
B. Slagging Index

FULL SCALE TESTS
A. Laboratory Tests - Scaling
B. Conesville Units 1 & 4
C. Tanners Creek Units 1 thru 3

PART 1

STEAM GENERATOR DESCRIPTION

STEAM/WATER FLOW PATH

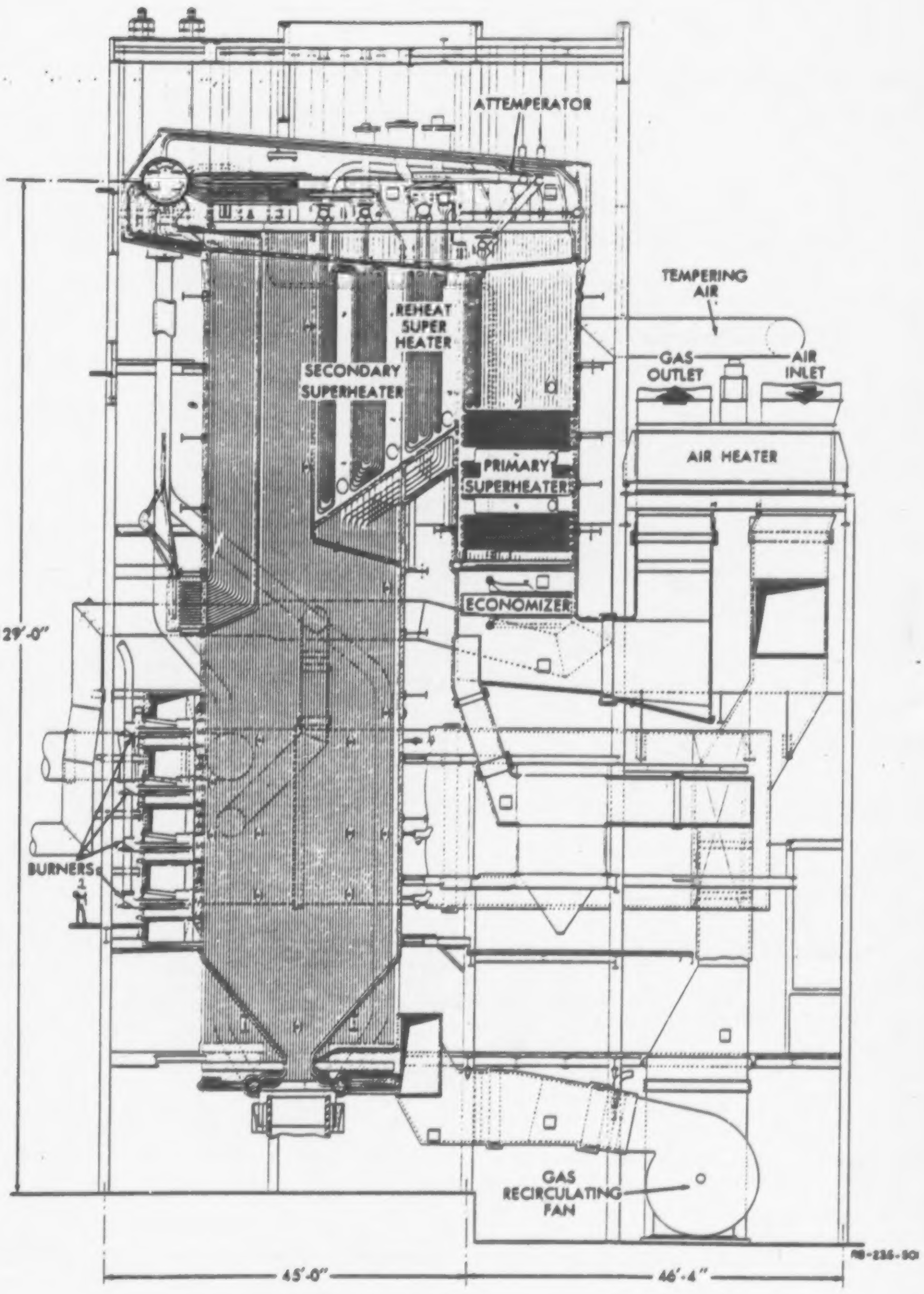
		Temp. (° F)
FEED PUMP	Water	
ECONOMIZER	Water	550
DRUM (LOWER)	Water	650
FURNACE	Water/Steam	650
DRUM (UPPER)	Steam	650
SUPERHEATER	Steam	1050
HIGH PRESSURE TURBINE	Steam	1050 to 700
REHEATER	Steam	700 to 1050
REHEAT & L.P. TURBINES	Steam	1050 to 140
CONDENSER	Steam to Water	

Illustration #1

AIR/GAS FLOW PATH

		Temp. (° F)
FORCED DRAFT FANS	Air	Ambient
AIR HEATER	Air	100 to 600
WINDBOX	Air	600
FURNACE	Gas	2600
ENTERING SUPERHEATER		2150
ENTERING REHEATER		1600
ENTERING ECONOMIZER		950
ENTERING AIR HEATER		725
ENTERING PRECIPITATOR/STACK		280

Illustration #2



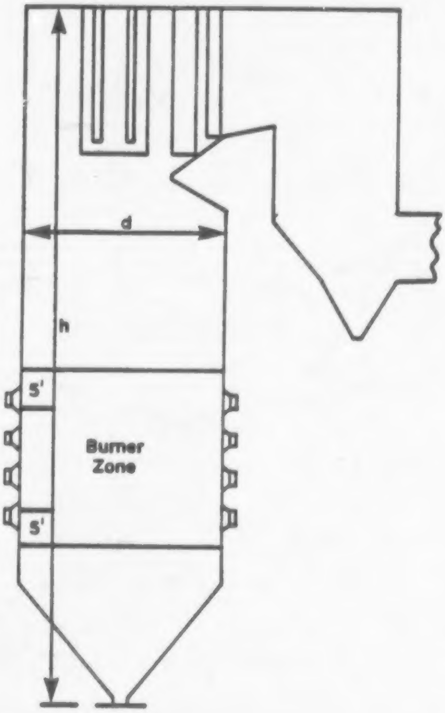
GLEN LYN UNIT 6

MAXIMUM CONTINUOUS CAPACITY	1,523,000 #/HR
DESIGN PRESSURE	2400 PSI
SUPERHEATER OUTLET PRESSURE	2075 PSI
INITIAL AND REHEAT STEAM TEMPERATURE	1050 F

BABCOCK & WILCOX CONTRACT RB-235

Illustration #3

Furnace definitions.



Plan Area Release Rate .... $\left[\frac{\text{input in fuel - BTU/HR}}{\text{w•d•FT}^2}\right]$ .... BTU/FT^2 HR

Burner Zone Release Rate .... $\left[\frac{\text{heat release*-BTU/HR}}{\text{effective burner zone area-FT}^2}\right]$ .... BTU/FT^2 HR

Furnace Release Rate .... $\left[\frac{\text{heat release*-BTU/HR}}{\text{furn. flat projected area-FT}^2}\right]$ .... BTU/FT^2 HR

Furnace Liberation .... $\left[\frac{\text{input in fuel-BTU/HR}}{\text{w•d•h-FT}^3}\right]$ .... BTU/FT^3 HR

Burner Input .... MKB/HR

*heat released and available from fuel and heated air.

Illustration #4

A.E.P. SUPERCRITICAL STEAM GENERATOR DESIGN PARAMETERS

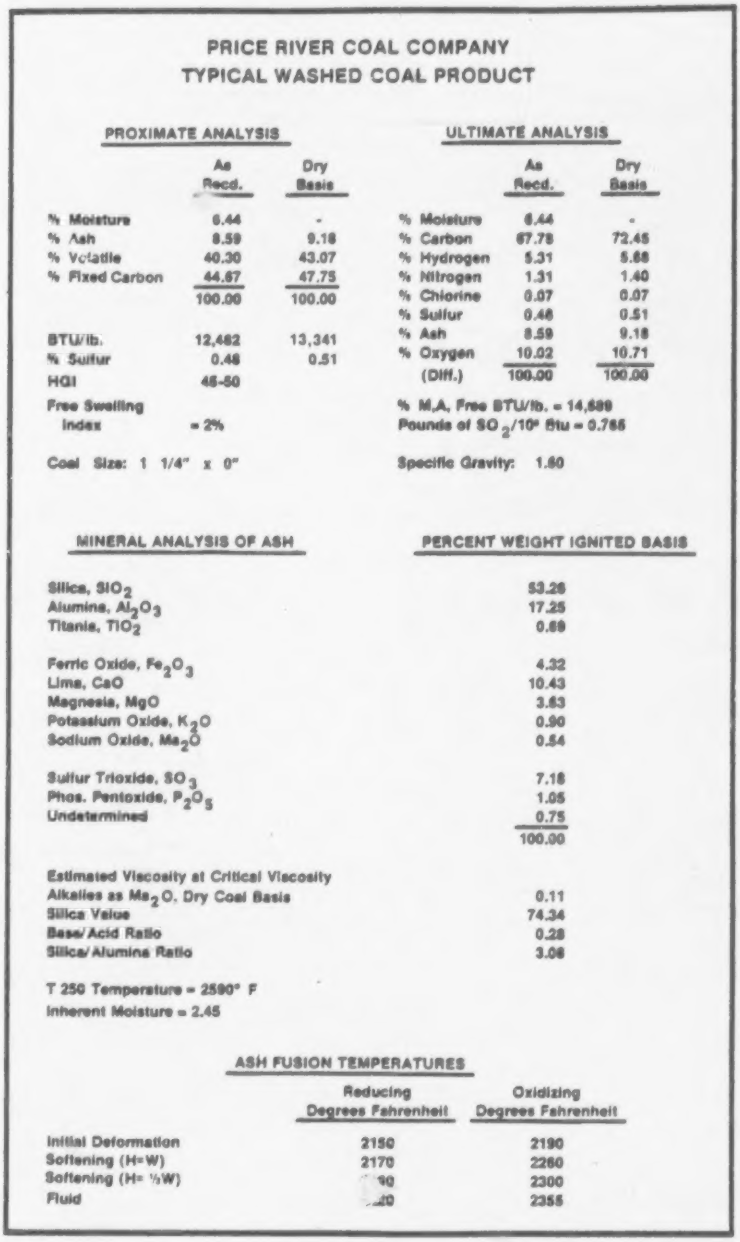
	UNIT			
	1980 Mountaineer 1300 MW Units	1970 Mitchell 1 & 2 800 MW Units	1967 Cardinal 1 & 2 600 MW Units	1980 Cardinal 1 & 2 With Revisions 600 MW Units
Unit Fuel Input MKB/Hr.	11,905	7,000	5,275	5,275
Furnace Projected Flat Area Release Rate BTU/Ft.^{2} - Hr.	152,300	131,000	166,000	120,300
Furnace Dimensions W x D x H	111' x 51' x 196'	82' x 40' x 157'	63' x 39' x 156'	63' x 39' x 156'
Furnace Volume Ft.^{3}	935,000	480,000	334,400	334,400
Plan Area Release Rate MBK/Ft.^{3} - Hr.	2.11	2.14	2.145	2.145
Number Burner Nozzles	98	36	40	50
Burner Input Per Nozzle all Mills In/One Out MKB/Hr.	122/131	195/233	132/165	106/132
Burner Zone Release Rate BTU/Ft.^{2} - Hr.	536,000	590,000	647,500	499,000
Burner Nozzle Spacing Horizontal	7'-0"	9'-7½"	9'-9"	9'-9"
Vertical	15'-0" 16'-0" 15'-0"	12' 12'	4'-2" 10'-0" 4'-2"	11'-9 3/4" 4'-2" 10'-0" 4'-2"
To S.W.	8'-10"	11'-3½"	7'-0"	7'-0"
To Hopper W.P.	8'-10"	8'-6"	7'-0"	7'-0"
Gas Temp. Leaving Furn. Ent. 9" Centers HVT° F	2210/1950	2137/	2190/1911	2180/1980
Furn Liberation (Volume) Rate BTU/Ft.^{3} - Hr.	11,960	14,600	16,000	16,000
Excess Air Con. Out.	17	16	18	(21)
Max. Gas Velocity Horizontal Pass Ft./Sec.	64.4	65	79 R.H. 75 Econ. (64 w/lanes)	51 R.H. (59 w/lanes)
Number Pulverizers @ 60 Tons/Hr.	14 MPS-89	6 MB-23 MPS-89	5 CR	5 MPS-89

Illustration #5

PART 2

COAL ANALYSIS

PREDICTING BOILER PERFORMANCE



PRICE RIVER COAL COMPANY
TYPICAL WASHED COAL PRODUCT

PROXIMATE ANALYSIS

	As Recd.	Dry Basis
% Moisture	6.44	-
% Ash	8.59	9.18
% Volatile	40.30	43.07
% Fixed Carbon	44.67	47.75
	100.00	100.00
BTU/lb.	12,482	13,341
% Sulfur	0.46	0.51
HGI	46-50	

Free Swelling Index = 2%

Coal Size: 1 1/4" x 0"

ULTIMATE ANALYSIS

	As Recd.	Dry Basis
% Moisture	6.44	-
% Carbon	67.78	72.45
% Hydrogen	5.31	5.68
% Nitrogen	1.31	1.40
% Chlorine	0.07	0.07
% Sulfur	0.46	0.51
% Ash	8.59	9.18
% Oxygen (Diff.)	10.02	10.71
	100.00	100.00

% M.A. Free BTU/lb. = 14,689

Pounds of $SO_2/10^6$ Btu = 0.766

Specific Gravity: 1.60

MINERAL ANALYSIS OF ASH	PERCENT WEIGHT IGNITED BASIS
Silica, SiO_2	53.26
Alumina, Al_2O_3	17.25
Titania, TiO_2	0.69
Ferric Oxide, Fe_2O_3	4.32
Lime, CaO	10.43
Magnesia, MgO	3.63
Potassium Oxide, K_2O	0.90
Sodium Oxide, Na_2O	0.54
Sulfur Trioxide, SO_3	7.18
Phos. Pentoxide, P_2O_5	1.05
Undetermined	0.75
	100.00
Estimated Viscosity at Critical Viscosity	
Alkalies as Na_2O, Dry Coal Basis	0.11
Silica Value	74.34
Base/Acid Ratio	0.28
Silica/Alumina Ratio	3.08

T 250 Temperature = 2590° F

Inherent Moisture = 2.45

ASH FUSION TEMPERATURES

	Reducing Degrees Fahrenheit	Oxidizing Degrees Fahrenheit
Initial Deformation	2150	2190
Softening (H=W)	2170	2260
Softening (H= ½W)	[illegible]	2300
Fluid	[illegible]	2355

Illustration #6

USE OF A COAL ANALYSIS REPORT TO HELP PREDICT PERFORMANCE OF A FUEL IN A BOILER

Presented by:

M. B. Doherty
Assistant Manager
Steam Generation Section
Plant Engineering Division
Canton, Ohio

Fuel represents the most important variable that affects the operation of our units. It is recognized that to achieve optimum performance in a steam generator the characteristics of the fuel should match the equipment that is provided to handle that fuel. One of the functions of the Steam Generation Section is to review fuel supplies, particularly those which represent large quantities that may be purchased under long-term contracts.

For this discussion we will review typical coal analyses that can be provided by our Huntington Lab. This is the type of analysis that is requested prior to making any recommendations on a fuel. We will briefly review how each one of the factors is evaluated as to its effect on unit performance.

PROXIMATE ANALYSIS

Moisture

Moisture primarily affects unit efficiency. In the case of some of our western coals, this is particularly important. The ratio of hot air vs. tempering air required to dry out the coal in the primary air to a pulverizer must be considered.

Ash

Ash is a material that must be handled through all phases of the steam generation cycle. The quantity and chemistry of the ash represents what is probably the most significant item affecting boiler availability and indirectly, heat rate and maintenance cost. Much of the fuel suitability analysis is focused on this property.

Volatile Matter

Volatile matter contains the hydrogen and hydrocarbons that sustain ignition. With some exceptions, we normally require that the minimum volatile matter on any coal to be purchased be 25%.

Fixed Carbon

Fixed carbon represents what is left. The sum of the moisture, ash, volatile matter, and fixed carbon represents 100% of the fuel.

Sulfur

The sulfur content in a fuel affects the overall operation of the unit in many ways. The form of the sulfur is also very important. This will be discussed later. The content of sulfur in the coal represents the primary indication as to the amount of SO_2 that will be produced. It is also the primary indication as to the degree of corrosion that we might expect in both the high and low temperature regions of the boiler. Coal ash corrosion can be directly related to sulfur content. The amount of SO_2 produced and retained in the flue gas controls the dewpoint of the flue gas in the lower temperature regions of the unit such as the air heater and precipitator.

BTU

BTU is the heating value of the coal. When analyzing different fuels, we normally like to put all parameters on the common basis of pounds per million BTU. For example, the ash may be expressed for analytical purposes as pounds of ash per million BTU. This distinction, at times, can be quite important.

Ash Fusion Temperatures

In a laboratory, ash fusion temperatures of an ash are run in both oxidizing and reducing atmospheres. Traditionally, engineers would look at reducing atmosphere fusion temperatures in wet bottom units and oxidizing atmosphere temperatures in dry bottom units. In fact, we normally operate to provide an oxidizing atmosphere in all of our boilers. However, we recognize that reducing conditions do occur in localized regions. In cyclone wet bottom units, this is probably true in areas of the floor and portions of the cyclone. In pulverizer coal units, it has been shown that areas around the burners are frequently in a reducing zone. The particular analysis shown does not indicate a great difference between reducing and oxidizing temperatures. There are many fuels, however, where this difference can be 400°-500°. This difference between oxidizing and reducing temperatures points out the importance of balanced fires. A balanced fire will have all burners operating in an oxidizing atmosphere. This will minimize slagging and reduce the amount of excess air required in the unit. For purposes of discussion, when the fusion temperature of a coal is referred to it normally means the hemispherical temperature in either a reducing or oxidizing atmosphere. It is important to be specific.

Grindability

Hardgrove grindability is the single most important property of a fuel affecting pulverizer capacity. In the AEP System, there is an enormous range of grindability of coals. Some of our East Kentucky coals have "grinds" of 35-40. There are also some coals, particularly in southern Virginia, with "grinds" up to 80 or 90. All pulverizers have their capacity rated at 50 grindability. "Grinds" above 50 will result in increased pulverizer capacity. Grindability below 50 will have reduced output. As an example, the MPS pulverizer is rated at 60 tons per hour. If the grindability were 40, the capacity of this pulverizer would be 48 tons per hour. If the "grind" were 60, the capacity would be 71 tons per hour.

Ultimate Analysis

The ultimate analysis is used primarily in heat rate tests. We do not use it for fuel suitability analysis.

Forms of Sulfur

The sulfur forms are pyritic, sulfate, and organic. These forms are considered in an effort to predict pulverizer wear. In addition, coals with high pyritic sulfur content would be expected to be slagging coals. Since pyritic sulfur contains iron, it has a better possibility of being removed by either the magnets or in the pulverizer pyritic system.

Ash Analysis

It is the ash analysis that tells us what the constituents of the ash are. The constituents along with the total quantity provide an indication of the future performance and availability of a unit.

Silica

Silica is an indication of the quantity of sand in a unit. This constituent is acidic and is indicative of the abrasive potential of the ash in the coal.

Iron

Iron, much of which is tied up in pyritic form, is a basic constituent of the coal. In eastern coals, the iron content provides an important indication of the slagging potential of a fuel.

Aluminum and Titanium

Aluminum and titanium are acidic, and are normally in the form of clay.

Calcium and Magnesium

Calcium and magnesium are very significant elements in western coals. In eastern, they are relatively small in quantity. They are very high in resistivity and can affect precipitator performance.

Potassium and Sodium

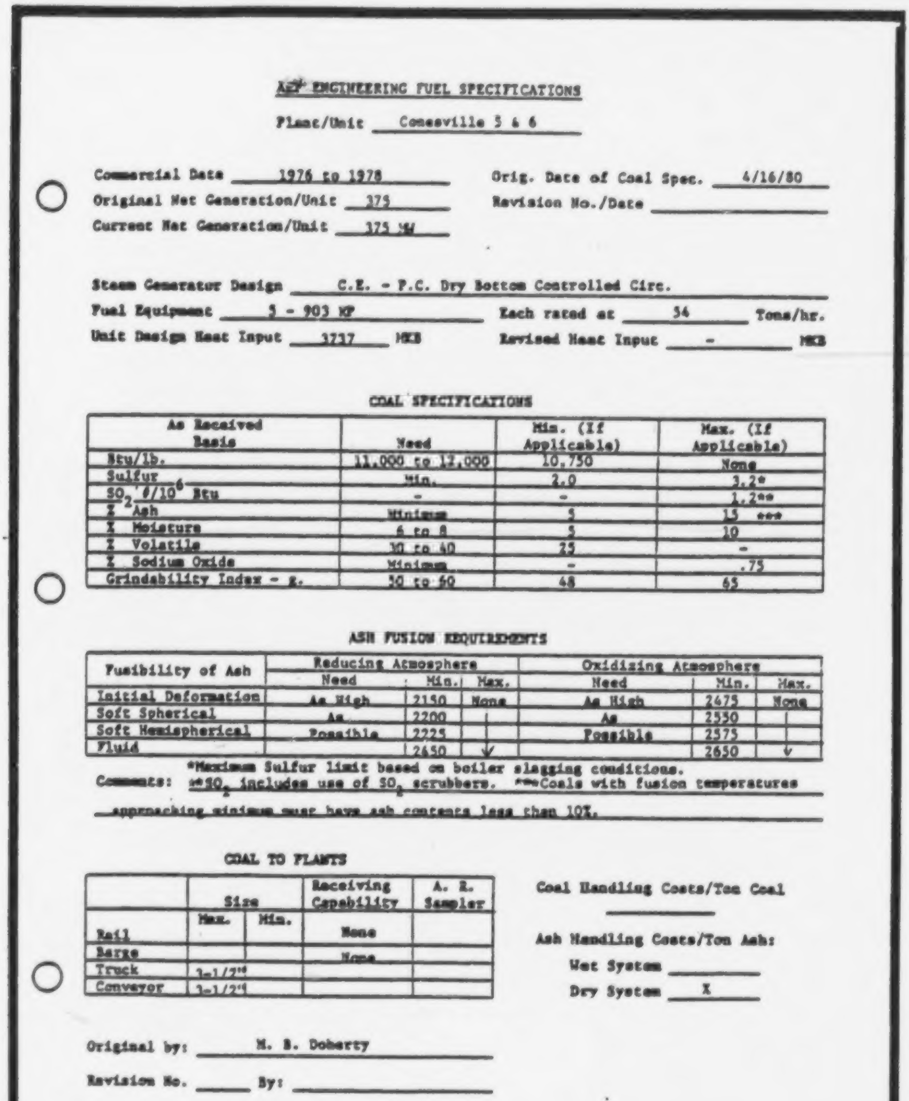
Potassium and sodium, with particular emphasis on sodium, are the prime contributors to fouling in the convection pass. There have been a few occasions where salt has been used to thaw coal in the winter. This has led to severe pluggage in the areas of the convection pass that were very difficult to remove. Coals with high sodium content should be avoided.

The base acid ratio of the constituents of the ash represents an indication of the slagging potential and fouling potential of the ash in a coal. Various quantitative methods have been developed to predict this potential.

SUMMARY

It is very important that no single parameter be considered completely by itself. All of the elements of a fuel analysis interrelate and must be considered as part of the whole.

REPRESENTATIVE SPECIFICATION SHEET



AEP ENGINEERING FUEL SPECIFICATIONS

Plant/Unit Conesville 5 & 6

Commercial Date 1976 to 1978
Orig. Date of Coal Spec. 4/16/80
Original Net Generation/Unit 375
Revision No./Date
Current Net Generation/Unit 375 MW

Steam Generator Design C.E. - P.C. Dry Bottom Controlled Circ.
Fuel Equipment 5 - 903 RP
Each rated at 54 Tons/hr.
Unit Design Heat Input 3717 MKB
Revised Heat Input - MKB

COAL SPECIFICATIONS

As Received Basis	Need	Min. (If Applicable)	Max. (If Applicable)
Btu/lb.	11,000 to 12,000	10,750	None
Sulfur	Min.	2.0	3.2*
SO_2 #/10^6 Btu	-	-	1.2**
% Ash	Minimum	5	15 ***
% Moisture	6 to 8	5	10
% Volatile	30 to 40	25	-
% Sodium Oxide	Minimum	-	.75
Grindability Index - g.	50 to 60	48	65

ASH FUSION REQUIREMENTS

Fusibility of Ash	Reducing Atmosphere			Oxidizing Atmosphere		
	Need	Min.	Max.	Need	Min.	Max.
Initial Deformation	As High	2150	None	As High	2475	None
Soft Spherical	As	2200		As	2550	
Soft Hemispherical	Possible	2225		Possible	2575	
Fluid		2450	↓		2650	↓

Comments: *Maximum Sulfur limit based on boiler slagging conditions. **SO_2 includes use of SO_2 scrubbers. ***Coals with fusion temperatures approaching minimum must have ash contents less than 10%.

COAL TO PLANTS

	Size		Receiving Capability	A. R. Sampler
	Max.	Min.		
Rail			None	
Barge			None	
Truck	3-1/2"			
Conveyor	3-1/2"			

Coal Handling Costs/Ton Coal

Ash Handling Costs/Ton Ash:
Wet System
Dry System X

Original by: M. B. Doherty
Revision No. By:

Illustration #7

PART 3

APPLICATION ANALYSIS

DATA SUMMARY
WASHED vs. ROM COAL

	PRICE RIVER ROM COAL SEAM D ONLY	PRICE RIVER WASHED COMPOSITE 68% SEAM D 32% SUBSEAM C	U.P. & L. WILBERG MINE ROM	U.P. & L. WILBERG MINE WASHED
BTU A/R	10,680	12,482	10,767	12,201
ASH % A/R	18.76%	8.59%	17.18%	8.93%
LBS. ASH/10^6 BTU	17.56	6.88	15.95	7.32
FUSION TEMPERATURE				
H=W RED.	2310° F	2170° F	2350° F	2250° F
B/A RATIO	0.18	0.28	0.21	0.32
SULFUR % DRY	0.68%	0.51%	0.59%	0.53%
SILICA/ALUMINA RATIO	3.54	3.08	3.40	3.01
SODIUM (NA_2O)	0.36	0.54	2.40	1.42
SLAGGING POTENTIAL	HIGH	LOW	MEDIUM/HIGH	LOW/MEDIUM

Illustration #8

PRICE RIVER COAL
SLAGGING POTENTIAL
ROM VS. WASHED COAL

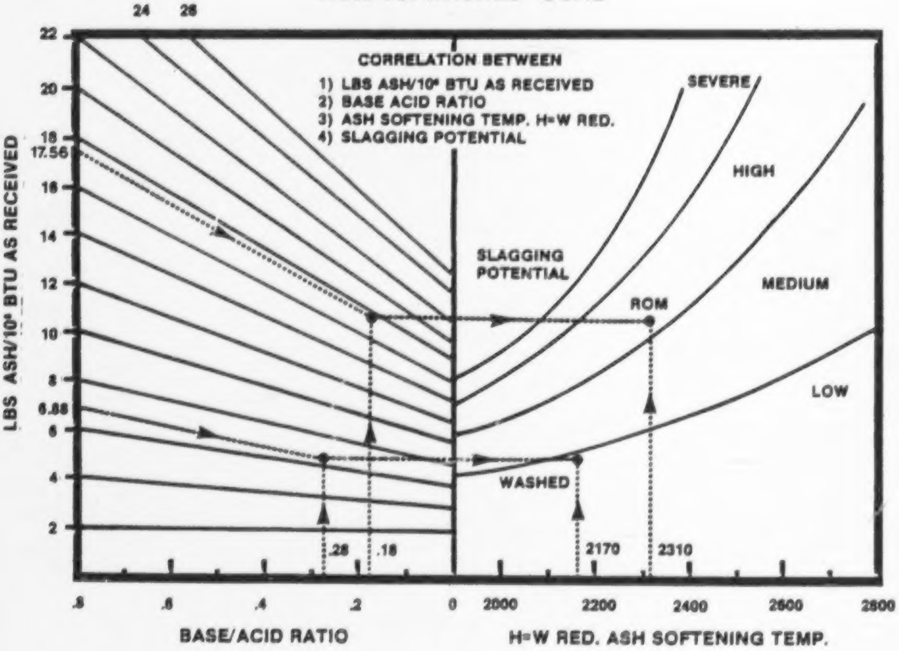
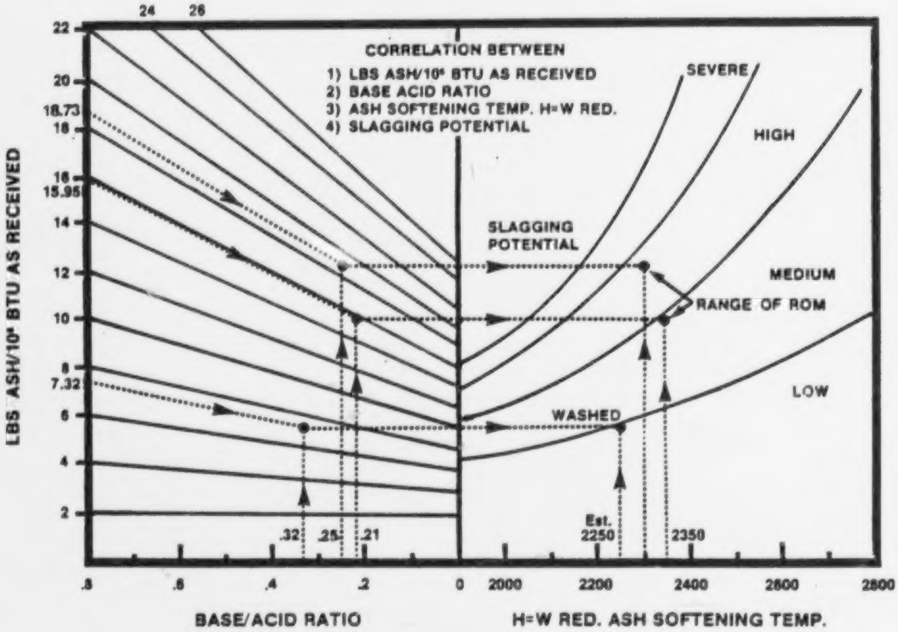


Illustration #9

UTAH POWER AND LIGHT
WILBERG MINE
ROM VS. WASHED COAL



ROM 1 : 15.95 # ASH/10^6BTU; B/A = .21; H=W = 2350
ROM 2 : 18.73 # ASH/10^6BTU; B/A = .25; H=W = 2300

Illustration #10

SLAGGING POTENTIAL FOR OHIO #6 COAL

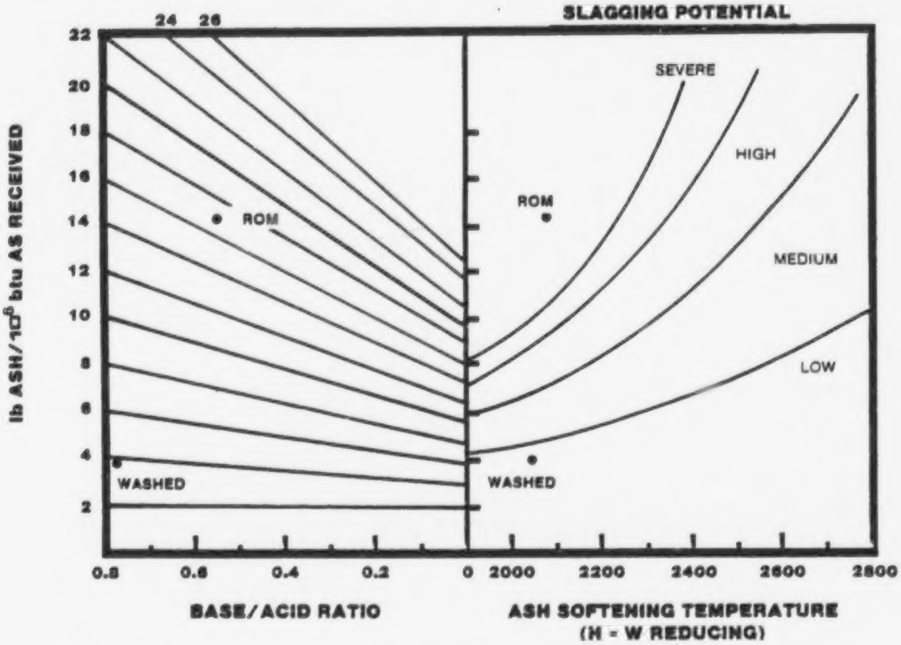


Illustration #11

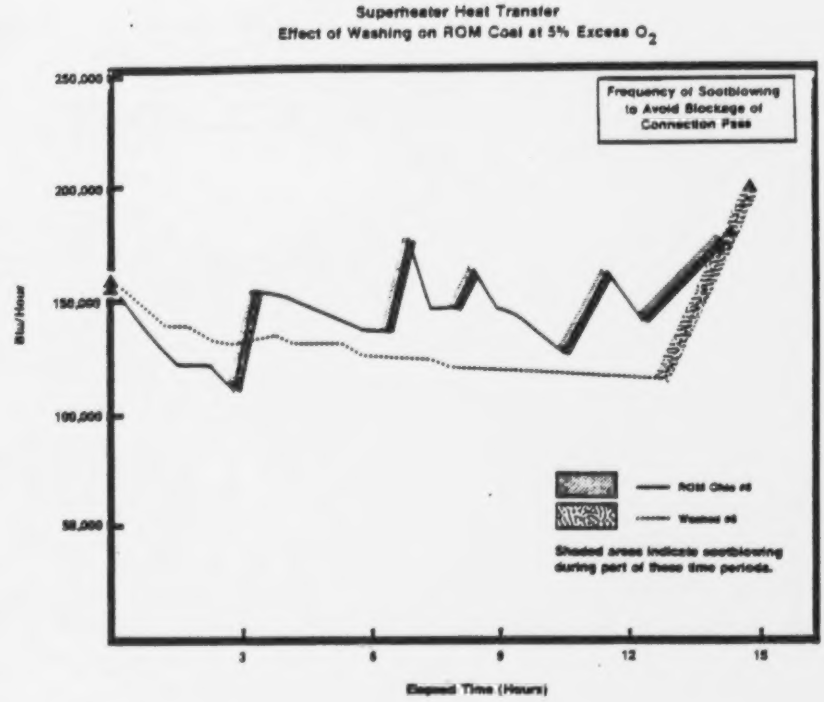


Illustration #12

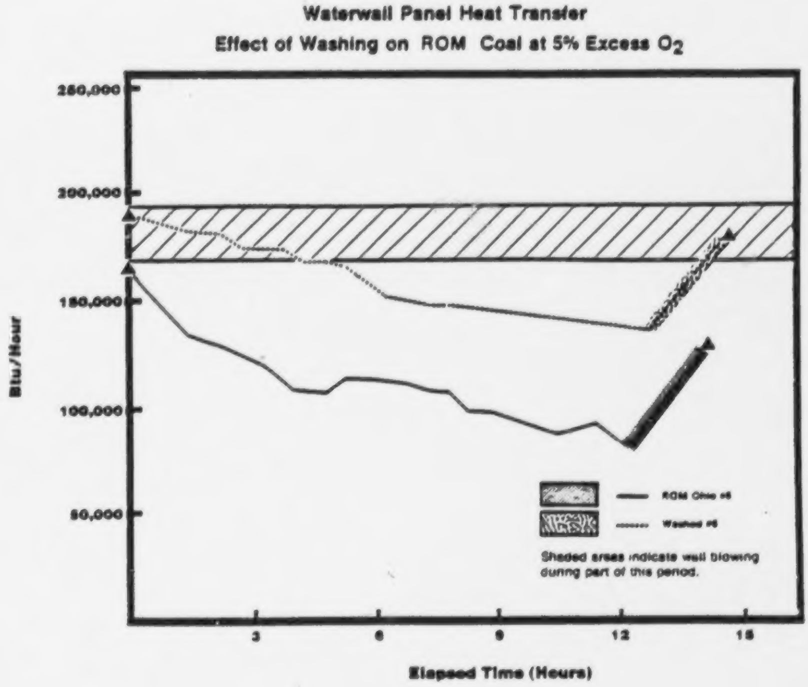


Illustration #13

TANNERS CREEK PLANT
EXPERIENCE WITH PRICE RIVER COAL

Tanners Creek Plant, located in Lawrenceburg, Indiana, consists of four fossil fuel fired boilers, three of which utilize washed Price River coal. Units 1 and 2 are 150 MWN, Babcock & Wilcox, pulverized coal, dry bottom, roof fired, subcritical units with a 930,000 lbs./hr. steam flow. Unit 3 is a similarly designed 215 MWN unit with a 1,335,000 lbs/hr. steam flow.

Prior to 1973 the units were fired on a high sulfur Midwestern bituminous coal. However, in 1973 due to environmental considerations, the fuel supply was changed to a low sulfur bituminous R.O.M. coal produced at the Price River Mine.

This R.O.M. coal was burned at Tanners Creek Units 1 thru 3 from 1973 to 1976 during which time the units experienced a significant decline in unit availability due to high ash content in the fuel. Beginning in 1976 a program was initiated to convert the Price River coal from a R.O.M. product to a washed coal in order to improve unit availability and extend wear life in coal handling equipment.

Since 1979 Tanners Creek Units 1 thru 3 have been burning 100% washed Price River coal with a significant increase in unit availability. The following chart illustrates the effect of fuel quality on unit availability.

	Pre 1973	1973-1978 R.O.M. Price River	'79-Present Washed Price River
PROXIMATE COAL ANALYSIS			
Moisture %	10.9 to 11.2	6.7 to 6.9	8.5 to 9.0
Ash %	13.0 to 13.4	10.5 to 18.5	7.9 to 8.2
Btu	10,800 to 11,000	10,680 to 11,825	12,200 to 12,500
Sulfur %	3.5 to 3.75	.57 to .63	.46 to .56
UNIT OPERATION			
Effective Availability %	80.8	70.3	88.8
Effective Forced Outage Rate %		22.4	8.5
Pulverizer Life hrs.	11,000	8,500	13,400

Illustration #14

TANNERS CREEK UNITS 1, 2 & 3 COMPOSITE FUEL QUALITY AND ITS EFFECT ON UNIT AVAILABILITY FOR FIVE CONSECUTIVE YEARS OF 1976-1980

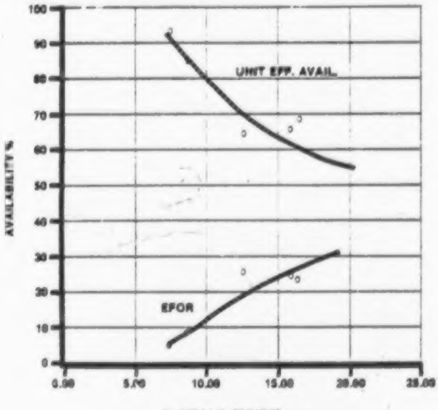


Illustration #15

ECONOMICS OF IMPROVED UNIT OPERATION WITH HIGHER QUALITY COAL

(1)

System Production Cost Savings

a) Total generation capability (Mwh) will increase offsetting purchased power requirements.

b) Reduction in fuel usage associated with improved heat rate due to increased cycle efficiency. Potential areas include:

   i) Lower exit gas temperature by improved cleanliness of heat transfer surfaces, the reduction in steam flow to air preheating coils, or lower excess air.

   ii) Higher turbine cycle efficiency due to improved availability and load factor.

   iii) Lower annual start-up and non-generating oil use due to improved unit availability.

(2)

Ability and the Associated Cost of Deferring New Installed Generation Due to Improved Peak Unit Capability and Forced Unit Outage Time

(3)

Reduction in Maintenance Costs Due to Improved Coal Quality

a) Fuel handling costs - fewer tons moved for given Mwh output beginning at the mine, through the transportation phase, and finally to the burner within the boiler.

b) Lower ash collection and handling costs from the dust collector to the disposal area.

c) Lower pulverizer wear rates which increase the time period between rebuilds. This reduces curtailment losses and maintenance expense.

d) Lower costs for ash disposal landfill areas.

e) Lower erosion rates in high velocity areas of boiler.

f) Lower potential for furnace slagging or fouling which would produce a forced unit outage. This also reduces the need for on-line ash cleaning through the use of sootblowers. This further reduces the potential for a forced outage, as well as maintenance expenses relating to sootblower repairs.

(1)

SYSTEM PRODUCTION COST SAVINGS

Total Generation Capability -

If the utility is a net buyer of power to meet internal load, what is the average cost of that purchased power during a given year? The system savings due to higher internal electrical production is calculated as follows:

$$\left[\text{Total offset in purchased power } (\text{Mwh}_1 - \text{Mwh}_2) \times \text{Average Cost of Purchased Power (\$/Mwh)}\right]$$

MINUS

$$\left[\text{Mwh}_1 \times \text{Incremental Production Cost}^{(1)} - \text{Mwh}_2 \times \text{Incremental Production Cost}^{(2)}\right]$$

$\underline{\text{Mwh}_1}$ =

$$\text{Unit Name Plate Rating} \times (\text{UFOR}_1 + \text{PFOR}_1 + \text{SOR}_1)/100 \times 8760 \text{ hrs.} \times \text{demand factor}$$

with **IMPROVED** Coal

$\underline{\text{Mwh}_2}$ =

$$\text{Unit Name Plate Rating} \times (\text{UFOR}_2 + \text{PFOR}_2 + \text{SOR}_2)/100 \times 8760 \text{ hrs.} \times \text{demand factor}$$

with **BASELINE** Coal

$\underline{\text{Incremental Production Costs}}^{(1)}$ =

$$\left(\text{Mills/Kwh fuel} + \frac{\underline{\text{Maint. Cost}}}{\text{Mwh}_1 \times 1000} + \frac{\underline{\text{Operations Cost}}}{\text{Mwh}_1 \times 1000}\right) \times 1000 = \text{Total Production Costs, \$/Mwh}$$

$\underline{\text{Incremental Production Costs}}^{(2)}$ =

$$\left(\text{Mills/Kwh Fuel} + \frac{\underline{\text{Maint. Cost}}}{\text{Mwh}_2 \times 1000} + \frac{\underline{\text{Operations Cost}}}{\text{Mwh}_2 \times 1000}\right) \times 1000 = \text{Total Production Costs, \$/Mwh}$$

$\underline{\text{Fuel Costs}} = \text{\$/MMBtu} \times \text{Btu/Kwh} \div 1000 = \text{Mills/Kwh}$

Assume $\text{Mwh}_1 - \text{Mwh}_2$ does not exceed system purchased power.

OTHER VARIABLES:

Present Unit Forced Outage Rate, % = $UFOR_2$

Projected Unit Forced Outage Rate, % = $UFOR_1$

Present Partial Forced Outage Rate, % = $PFOR_2$

Projected Partial Forced Outage Rate, % = $PFOR_1$

Present Scheduled Outage Rate, % - SOR_2

Projected Scheduled Outage Rate, % - SOR_1

$$\text{Present Demand Factor} = \frac{\text{Total Mwh Generation in Period}}{\text{Rated Capability x Period Hours x E.A.}}$$

where E.A. = Effective or Equivalent Availability in Period.

Projected Demand Factor = as defined above.

SIMPLIFYING ASSUMPTIONS:

1) $SOR_1 = SOR_2$

This assumes the fuel quality will not affect requirements for scheduled outages. This is conservative, as experience indicates that boiler wear and resulting repair will decrease with improved fuel. However, other equipment repairs may historically have dictated the critical path of the scheduled outage.

2) Demand factors will not significantly change with fuel quality. This assumes that the potential for additional generation due to peak output will be offset by the higher incremental fuel costs resulting in early load shedding as dictated by economic dispatch.

(2)

DEFERRED INSTALLMENT OF NEW ADDITIONAL CAPACITY DUE TO HIGHER UNIT LOAD CAPABILITY

The additional peak capacity of a unit that can be realized on a consistent basis will, in effect, permanently defer the addition of new generating capacity. This will produce a savings to the company and customer of the equivalent cost per installed Kw of new capacity at the projected carrying charge for borrowed money.

Example:

The improved fuel quality produces an increase of 30 Mw in reliable, peak generating capacity. Depending upon the system load growth and overall capability, the added capacity will defe the need of a new 400-600 Mw unit by three to five months. At a projected installed cost for new generation with scrubbers of $1,000 to $1,500 per Kw, the capital carrying charges would theoretically total $1,600,000 to $2,400,000 per year.

(3)

REDUCTION IN MAINTENANCE COSTS WITH IMPROVED QUALITY FUEL

Variables: Boiler Design

- Heat release
- Velocity
- Material applications

Boiler Auxiliary Design

- Mill type and calibration
- Fuel handling equipment design and wear rates

Ash Handling and Disposal

- Wear on ESP and ash hopper removal system
- Disposal area costs
- Utilization of fly ash or bottom ash for resale

Studies indicated that with typical bituminous coals, the overall maintenance cost associated with lower ash content varies by a cost of \$10 to \$15 per ton of ash consumed in the feed coal. Typically, a 70 Mw unit with 80% equivalent availability will consume 222,000 tons of 10,600 Btu/lb., 12% ash coal annually. This yields an ash loading of 26,640 tons/year. The improvement in fuel to 12,400 Btu/lb., 7% ash coal produces 193,370 tons of coal consumed and 13,535 tons of ash loading through the system. The ash loading drop of 13,105 tons represents a potential maintenance cost reduction of \$130,000 to \$200,000 per year.

"Enhanced Coal Technology -- Coal's Market for the 80's"

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Senator WARNER. Thank you very much. The Chair will forgo submitting questions as originally planned in order to facilitate, hopefully, a more rapid progression by the witnesses. We are going to have to get along here.

Mr. Blackmore, that was a very indepth overview and I think it helps frame today's activities. I appreciate your participation very much.

We will now hear from Mr. Walter Hibbard, director, Virginia Center for Coal and Energy Research.

STATEMENT OF DR. WALTER R. HIBBARD, JR., UNIVERSITY DISTINGUISHED PROFESSOR OF ENGINEERING AND DIRECTOR, VIRGINIA CENTER FOR COAL AND ENERGY RESEARCH, VIRGINIA TECH

Dr. HIBBARD. My name is Walter Hibbard. I am a university distinguished professor of engineering and director of the Virginia Center for Coal and Energy Research at Virginia Tech. I was Director of the U.S. Bureau of Mines in 1965–68 under President Lyndon Johnson, and Coal Specialist and Deputy Director of the Energy Research and Development Office in the Federal Energy Office—later the Federal Energy Administration—under Presidents Nixon and Ford. A summary of my professional experience and several coal-related fact sheets are attached to my written testimony for your further information.

Thank you for the opportunity to testify before the subcommittee on this very important subject. Coal is important to the United States, to central Appalachia, and particularly important to the Commonwealth of Virginia.

My purpose today is to give you an overview about the state of the domestic coal industry, focusing on the central Appalachian States and particularly on the Commonwealth. I will also touch on the need for advanced coal technology as a stimulant to market revitalization and development.

During the first 28 weeks of 1983, U.S. coal production was 397 million short tons, down 14 percent from the same period in 1982. The National Coal Association's projection for 1983 is very optimistic. At the current rate, as projected, the 1983 production will be 738 million tons. The lowest since 1978. During this same period in 1983 central Appalachia which consists of Virginia, southern West Virginia, and eastern Kentucky, coal production was 138 million short tons, down 10 percent from the equivalent period in 1982. In spite of 1983's depressed market, central Appalachia, and particularly eastern Kentucky, has gained market shares. However, during the 28-week period, Virginia produced only 18 million short tons, down 25 percent as opposed to the 1982 period. As you will readily note, this drop in Virginia is much larger than that for the United States and central Appalachia. This projects to a yearly production of 33 million tons. Again, this will be the lowest production in Virginia for nearly 8 years. Virginia has produced a premium, high-quality coking coal which is also high cost. It is also high cost coal in central Appalachia and the United States primarily due to production methods required for thin seams and underground mining. The world steel industry is in the doldrums, operating at about 55 percent of capacity. The need for coking coal is suffering. Many U.S. companies are getting rid of their blast furnaces and building electric furnaces, which do not require the same amount of coke. Thus, Virginia has lost a substantial domestic market share in central Appalachia, the United States, as well as in the foreign market. There is an attachment to my written testimony which describes this.

During the first 6 months of 1983 the U.S. export market dropped 42 percent from the 57 million tons that were shipped during 1982. But worse, the Hampton Roads export market dropped 43 percent down from last year's 31 million tons. This drop at Hampton Roads possibly is occurring because of the limited need for coking coal and a change in mix. We are beginning to ship more and more steam coal out of Hampton Roads.

The steel industry, as I have mentioned, is tightening its belt and is going toward electric furnaces. I am doubtful that the need for coking coal will ever recover to the prerecession demand levels in the United States.

Therefore, there is an urgent need for new markets for our high quality, low sulfur coal. This next chart shows that the mining of coking coal has developed a downward slope. For a while, the exports were larger than the domestic use but now they are down very low. You can see the NCA estimate for 1983 and that is very optimistic. We need new markets for our high quality, low sulfur, low ash, high Btu coal. This coal can and must be tailored to meet modern market needs through advanced cleaning and processing techniques which you have already heard about. It must be available to compete with the petroleum and natural gas of the same quality and the same characteristics with respect to hydrocarbon content and purity levels. Realistically, it must be environmentally acceptable.

The new markets are at least four. Chemical feedstock is one market. Tennessee Eastman is building a coal acetic anhydride plant near Kingsport, TN. Prior to World War II, coal was the principal chemical feedstock and can be restored to this position. The Second market is as a boiler fuel to replace No. 6 and even No. 2 in the form of coal/water, coal/oil or coal/methanol slurries. Diesal fuel would be the third market. Don't forget Mr. Diesel, of railroad frame as we built the first railroad diesel engine to burn coal. I believe the potential to recapture the railroad market as a reasonably priced energy fuel supply for diesel locomotives exist. The last market would be as a home heating fuel in residential complexes, through the use of small, clean fluidized-bed furnaces, which we will hear about later on.

All these markets are technically achievable, but they have impediments which are economic and institutional. Acid rain is scaring everybody away from coal. Most of the scare is due to misinformation, I'm sorry to say.

My contribution in now to make these markets come about is to recommend a new coal extension service funded and administered by the Federal and State governments using well-trained county coal extension agents to assist the coal miner, just as the Agriculture Extension Service which was put in place to help the small farmer. In this State, many of the large coal companies are subcontracting their mining to small "mom-and-pop" operations. These operations do not have the technical, economic legal assistance the large companies have and they need it very badly. I propose a pilot operation in the State of Virginia in the seven counties mining coal to determine the need and utility of such an extension service. This is a way to help Virginia and other parts of the coal industry twofold.

Thank you very much for the opportunity to testify before the subcommittee. I will be pleased to answer any questions.

[The prepared statement of Dr. Hibbard follows:]

TESTIMONY OF WALTER R. HIBBARD, JR.

My name is Walter Hibbard. I am a University Distinguished Professor of Engineering and Director of the Virginia Center for Coal and Energy Research at Virginia Tech, here in Blacksburg, Virginia. I was Director of the U.S. Bureau of Mines in 1965-68 under President Lyndon Johnson, and Coal Specialist and Deputy Director of the Energy Research and Development Office in the Federal Energy Office -- later the Federal Energy Administration -- under Presidents Nixon and Ford in 1974. A summary of my professional experience and several coal-related fact sheets are attached to my written testimony for your further information.

My purpose today is to give you an overview about the state of the domestic coal industry, focusing on the central Appalachian states and particularly on Virginia. I will also touch on the need for advanced coal technology as a stimulant to market revitalization and development.

During the first 28 weeks of 1983, U.S. coal production was 397 million short tons, down 14.1 percent from the same period in 1982. During this same period in 1983 in central Appalachia -- which consists of Virginia, West Virginia, and eastern Kentucky -- coal production was 138 million short tons, down 10.2 percent from the equivalent period in 1982. In spite of 1983's depressed market, central Appalachia, and particularly eastern Kentucky, has gained some market share. However, during the 28-week period, Virginia produced only 18 million short tons, down 24.3 percent as opposed to the 1982 period. As you will readily note, this drop is much larger than that for the United States and central Appalachia. Then too, Virginia is a producer of premium, high-quality coking coal which is also high cost, primarily due to production methods required for thin seams and underground mining. With the world steel industry in the doldrums, the need for coking coal has also suffered. Thus, Virginia has collectively lost a substantial domestic market share in central Appalachia and the United States, as well as in the foreign export market.

In the first six months of 1983 the U.S. export market dropped 42 percent from the 57 million tons that were shipped during that period in 1982, but worse, the Hampton Roads' export market dropped 42.7 percent from the previous year's 31 million tons -- most likely due to the limited need for coking coal and a change in mix to steam or boiler coal.

The steel industry is tightening its belt, reducing output capacity and modernizing its production technology during the current recession. Electric furnaces, which use scrap metal in the production process, are replacing blast furnaces which use coke. At the moment, I am doubtful that the need for coking coal will ever recover to pre-recession demand levels in the United States.

Thus, there is an urgent need for new markets for our high quality, low sulfur, low ash, high btu coal. This coal can and must be tailored to meet modern market needs through advanced cleaning and processing techniques so it can -- to a degree -- replace petroleum and natural gas by competing with these commodities in quality relative to hydrocarbon content and purity levels, mainly sulfur and ash. Realistically, it must be environmentally acceptable and provide the same convenience as competing fuels.

As the new production technology and techniques -- now waiting in the wings -- are implemented, known and new markets for coal can be generated. Here are just a few examples:

1. As a chemical feedstock -- Tennessee Eastman is building a coal acetic anhydride plant near Kingsport, Tennessee. Prior to World War II, coal was the principal chemical feedstock and can be restored to this position.

2. As a boiler fuel -- in the form of coal/water, coal/oil or coal/methanol slurries which match the efficiencies of No. 6 fuel oil at a lower cost.

3. As a diesel fuel -- this in the form of powdered coal, of very high purity, in an oil carrier. Mr. Diesel originally designed his engine for coal. I believe it has the potential to recapture the railroad market as a reasonably-priced energy supply for diesel locomotives.

4. As a home heating fuel in residential complexes, through use of clean fluidized-bed furnaces -- coal would be cheaper, cleaner and as convenient as oil.

All of these new markets are technically achievable, but they have impediments which are economic and institutional. This afternoon, we hope to learn how to remove the impediments so we can make them happen.

My contribution to the "make-it-happen" testimony is to recommend a new coal extension service funded and administered by the U.S. Department of the Interior using well-trained county coal extension agents to assist the small coal miner, just as the agriculture extension service helps meet the needs of the small farmer. It would provide a valuable and needed service, but its success will depend on knowledgeable leadership and adequate funding.

Thank you for the opportunity to testify before this distinguished subcommittee. I will be pleased to answer any questions you have now or later.

Walter R. Hibbard, Jr.
University Distinguished Professor of Engineering
Virginia Polytechnic Institute and State University

Walter R. Hibbard, Jr. is a University Distinguished Professor of Engineering and Director of the Virginia Center for Coal and Energy Research at Virginia Polytechnic Institute and State University, Blacksburg, Virginia. In 1974, he served as Deputy Director and Specialist on Fossil Fuels in the Energy Research and Development Office of the Federal Energy Office. From 1968 to 1974, he was Vice President of Technical Services in the Owens-Corning Fiberglas Corp., Toledo, OH. Dr. Hibbard is a member of the Board of Directors of the Norton Co. in Worcester, Massachusetts.

He served as Director of the Bureau of Mines in the U.S. Department of the Interior, Washington, D.C. from 1965 to 1968. Prior to this appointment he was manager of the Metallurgy and Ceramics Department of General Electric Research Laboratory, Schenectady, New York. After serving as a reserve officer in the U.S. Department of the Navy's Bureau of Ships during World War II, Dr. Hibbard taught Metallurgy in the School of Engineering at Yale University. He also served as an adjunct professor of Metallurgy at Rensselaer Polytechnic Institute.

Dr. Hibbard is a member of the National Academy of Engineering and served on its committees on Public Engineering Policy. He was Chairman of the Materials Advisory Board and also the Building Research Advisory Board of the National Research Council. He served on the National Academy of Sciences' Committee on the Survey of Materials Science and Engineering (COSMAT). He is a Fellow of the American Academy of Arts and Sciences, the American Association for the Advancement of Science, the American Ceramic Society, the American Society for Metals, and the Metallurgical Society of A.I.M.E. He was President of the American Institute of Mining, Metallurgical, and Petroleum Engineers for 1967-1968, and he received its James Douglas Gold Medal, Rossiter W. Raymond Award, and the Mineral Economics Award.

He graduated from Wesleyan University with a degree in Chemistry and received his doctorate in Engineering from Yale. He has received honorary degrees from Michigan Technological University and from Montana College of Mineral Science and Technology. He is a registered professional engineer in the states of Virginia, OH, and Connecticut.

RECENT TRENDS IN VIRGINA'S COAL PRODUCTION

In 1982, Virginia's coal production dropped to 37.2 million tons from 41.9 million tons in 1981, a reduction of 11.2 percent, while U.S. coal production remained stable at 824 million tons. During the first five months of 1983, Virginia's coal production sank 25 percent compared to the first five months of 1982, and U.S. coal production declined 15 percent. During this same period, Virginia's share of U.S. coal production dropped from 5.12 percent to 4.23 percent, a loss of nearly 1 percent of market share (EIA, 1982a; 1983a,b).

Hampton Roads terminals exported 53 million tons in 1982, up 11.3 percent from the 47.3 million tons exported in 1981. However, during 1982, Virginia-produced coal exported through Hampton Roads dropped 6.9 percent from 13.0 to 12.1 million tons. All of this coal was transported by the Norfolk Southern Corporation, which increased its haulings for foreign export from 33.6 million tons in 1981 to 34.6 million tons in 1982. Of this, eastern Kentucky coal gained 4.6 million tons reaching 9.9 million tons in 1982. Concurrently, domestic coal traffic from Hampton Roads increased from 2.4 million tons in 1981 to 4 million tons in 1982 (EIA, 1983b; Hunter, 1983).

The above information suggests that the Virginia coal industry is not maintaining its production share of the U.S., central Appalachian, or Hampton Roads market activity. The loss, it seems, results from the lower competitive cost of eastern Kentucky coal. If this trend continues, the future for Virginia's coal industry looks very grim, indeed.

To reverse this trend, the delivered costs of Virginia-mined coal must be reduced to meet the competition from eastern Kentucky. Several Virginia coal producers (Paramont and Westmoreland, Virginia Coal Council, 1983) maintain that when they match the mine-mouth prices in eastern Kentucky, they are beaten by lower competitive transportation costs. Significantly, the railroads are attracted to eastern Kentucky coal because of its larger reserves, larger production capacity, lower mining costs, lower transportation costs and railroad-owned reserves.

It is believed that Norfolk Southern can provide faster turn-around time for ships at Hampton Roads than can CSX. Faster turn-around time reduces demurrage and thus lowers ship transportation costs. If this is true, Norfolk Southern may gain export market-share from CSX at Hampton Roads. However, CSX is still the largest coal transporter in the United States, and may be capable of meeting its transportation competition (Anon., 1983e).

THE SMALL BUSINESS PORTION OF THE COAL INDUSTRY: TECHNICAL AND ECONOMIC NEEDS

The United States coal industry consists of a few very large operations (most owned by petroleum or steel corporations), a few medium-sized operations, and a very large number of small operations. The small operations usually employ 14 or fewer people, or mine less than 200 acres. They are often family ventures, whose members serve all functions, providing a low-overhead, intensely-loyal, hard-working and high-productivity performance. Such small operations provide great flexibility to the supply system.

Serving as a buffer with low overhead and low investment, they can quickly enter the business with rented equipment when the market needs them, and quickly retire from business when the market softens. Many large coal companies now lease their coal reserves to the small miner with the proviso that they buy back the mine's production at a fixed price.

Virginia had 881 coal mines during 1981: 261 were strip mines; 54 were auger mines, and 566 were underground mines. Of these 393 mines were small. Nearly 42 million tons of coal were supplied -- 33.5 million tons from underground mines and 10.8 million tons from small mines. At least one large coal-company conglomerate in Virginia contracts for all of its mining services.

The small coal miner has no technical or economic resources. No research, no technical services, no economic or legal services. Since he rents equipment, he cannot rely on the equipment manufacturer for technical advice. Like the small farmer of a century ago, he needs an extension service suited to his particular needs.

Virginia is ideally suited as a test state for the coal mine extension service. Coal is mined in seven contiguous counties, but is concentrated in two. It is typical of the Appalachian coal area, but particularly of the central Appalachian region. It abutts the two largest coal-producing areas, eastern Kentucky and southern West Virginia. It has been the state hardest hit by the recent recession. This is because it produces premium metallurgical coal for the steel industry, which will never recover to its pre-recession volumes and is changing to technology which does not require coal. It produces the highest-cost coal and the highest-quality coal. During the last two years, it has been losing market position, both in the United States and in central Appalachia, as well as in the export market.

Most importantly, the Virginia coal district includes Blacksburg where Virginia Tech is located with its internationally-known Mining and Minerals Engineering Department. Outstanding faculty from this department are available to provide technical and economic support to the proposed extension service. The Virginia Center for Coal and Energy Research is also located at Virginia Tech.

Finally, the area is served by the Virginia Coal Council which recognizes the need for a coal-mining extension service, and will provide local support for the activity. Of course, an agricultural extension agent is stationed in each of the seven coal producing counties, and can help provide local county coal-industry contacts to the coal extension service.

Production (Million Tons) and Regional Percentages

	1980	1981	1982	1983 (28 wks)
United States	829.7	823.8	833.4	397.3
Central Appalachia*	271.8	272.7	277.3	137.9
Percent of U.S. production	32.8%	33.1%	33.3%	34.7%
Eastern Kentucky	109.2	117.9	111.4	56.5
Percent of central Appalachian production	40.2%	43.2%	40.2%	41.0%
Virginia	41.0	42.0	37.2	18.2
Percent of central Appalachian production	15.1%	15.4%	13.4%	13.2%
West Virginia	121.6	112.8	128.8	63.2
Percent of central Appalachian production	44.7%	41.4%	46.4%	45.8%

(Source: Energy Information Admin. Weekly Coal Reports DOE/EIA 83-1 to 29)

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*Central Appalachia includes eastern Kentucky, Virginia and West Virginia.

VIRGINIA COAL PRODUCTION: IMPACTS AND PROJECTIONS

POTENTIAL FOR INCREASED DEMAND

We anticipate that U.S. annual coal production will increase to 1.5 billion tons in 1995, based on the Center's recent revisions to earlier projections developed by ICF (1981), EIA/DOE (1982b,d,e), and NCA (1983). Appalachian output is projected to drop from about 50 percent to 40 percent of total U.S. production as western coals become more dominant. Virginia's yield is projected to remain at nearly 5 percent of the U.S. total. Because the metallurgical coal[1] market is flat (Anon., 1983d), Virginia's anticipated increase in coal production must penetrate the steam coal market.[2] Increased steam coal sales assume Virginia's coal-delivered price will remain competitive with eastern Kentucky and southern West Virginia, and that Virginia's low-sulfur premium coal will be sold as compliance coal in the utility market and as a pulverized coal-water slurry substituting for residual or No. 6 fuel oil (Hibbard, 1983).

PULVERIZED COAL-WATER SLURRY OR COAL-OIL MIXTURE FUELS

Pulverized coal-water slurry (Bacon, 1983) and coal-oil mixtures (Anon., 1980) are being developed as substitutes for No. 6 fuel oil in numerous boiler applications, using the same storage and handling facilities as No. 6 fuel oil, and can be transported by pipeline. This slurry, or mixture, requires low-sulfur, low-ash coal to compete successfully with No. 6 fuel oil (Walia, 1982). High quality Virginia coal is appropriate for this application, and can utilize coal fines. A potential market for 150 million tons would exist in the eastern United States if all oil-fired boilers were converted to burn coal. Florida Power and Light Company is presently using a coal-oil mixture (Anon., 1980). Vepco is evaluating the technical and economic viability of a coal-water slurry fuel (Brown, 1983).

COMPETITIVE DELIVERED PRICES

Virginia currently is the high-cost (marginal) coal supplier for both world and domestic markets in terms of mine-mouth and delivered prices.[3] Its position in the market at any one time is determined by the quality of its coal, delivery reliability, and the availability of coal from other sources at a competitive or better price (Bacon, 1982a,b). For these reasons, only about 13 million tons of the 47 million tons of coal exported through Hampton Roads in 1980 came from Virginia

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[1] Metallurgical coal is low-sulfur, low-ash, medium-volatility coking coal used to make coke. It is cleaned, and is usually less than 1 percent sulfur and 8 percent ash. Seventy to eighty percent of Virginia's annual coal production is metallurgical coal.

[2] Steam coal is burned in boilers to make steam in an electric utility plant. It is usually not cleaned, and is sold by Btu, sulfur, moisture, and ash content. Compliance coal contains less than 1.2 pounds of sulfur dioxide per million Btu. Metallurgical coal can be burned in boilers if it is blended to avoid caking.

[3] Delivered prices include mining, gathering, transportation, preparation, port, shipping, and distribution costs.

(Virginia Port Authority, 1982). Its coal exports peaked at a time when strikes in Australia limited the availability of coal to Japan, and political unrest in Poland limited the availability of coal in Europe. When Hampton Roads' exports peaked at 53 million tons in 1982, Virginia's coal exports actually dropped to 12.1 million tons, a loss of 4.9 percent of market share (EIA, 1983b).

Of competing states within the central Appalachian region, southern West Virginia has the largest reserves, the largest production, and produces the most coal for export. Eastern Kentucky has the lowest priced coal, and Virginia has the highest quality coal as shown in the following tables.

The demonstrated bituminous coal reserve base, as of January 1980, for Virginia, eastern Kentucky, and southern West Virginia (EIA, 1982c), in million tons, was as follows:

	Underground	Surface	Total	Avg. Sulfur
Virginia	2,625.3	846.2	3,471.4	0.9
E. Kentucky	8,723.3	4,204.2	12,927.5	1.1
West Virginia	34,581.1	5,195.1	39,776.2	1.6

(Source: EIA, 1982c)

Distribution of coal reserves (Thomson and York, 1975) in million tons by sulfur content is:

	≤.4%	.5-.6%	.7-.8%	.9-1.0%	1.1-1.4%
Virginia	60	581	809	637	767
E. Kentucky	26	1,228	3,049	2,265	1,816
So. West Virginia (20 counties south of 38°30' north latitude)	310	3,819	5,657	3,207	3,099

(Source: U.S. Bureau of Mines Information Circular 8680, 1975)

Distribution of coal reserves in billion short tons by servicing railroad is as follows:

	CSX (B&O)	CSX (C&O)	TOTAL (NS)	CSX (L&N/Clinch)	TOTAL CSX
Virginia	---	---	2.1	1.4	1.4
E. Kentucky	---	3.7	3.0	6.1	9.8
So. West Virginia	2.6	10.7	7.4	---	13.3

(Source: URS in association with A. D. Little, 1981)

Average mine price, 1980 dollars per short ton, was as follows:

	Underground	Surface	Weighted Average
Virginia	$36.47	$28.05	$34.58
E. Kentucky	30.98	26.23	28.72
West Virginia	36.46	28.72	34.88

(Source: EIA, 1982c)

Virginia coal production by county in 1980 was:

	Million Tons	Avg. Sulfur	Avg. Ash
Buchanan	17.7	0.8%	8.2%
Wise	12.5	0.6	9.4
Dickenson	5.9	0.6	8.2
Tazewell	2.2	0.6	6.2
Russell	1.5	0.5	7.4
Lee	1.2	0.7	7.0
Scott	0.01	0.9	6.4
Total:	41.01	0.7%	8.7%

(Source: Varndell, 1982 Marketing Digest, MVN Pub.)

Hampton Roads is forecast, by many analysts, to retain its share of the met-coal exports market, following the economic recovery of the steel and foundry industries, even though Australia will become the world's largest met coal exporter. Study estimates assume that Virginia steam-coal production will rise by a factor of four. If its delivered coal price is not competitive with eastern Kentucky and West Virginia prices, Virginia will lose its market share (Hibbard, 1983).

A Japanese buyer (Tada, 1981) stated the $20-a-ton price differential for U.S. coal, as compared to Australian, South African or Canadian coals, was not acceptable and that the industry must increase productivity, decrease rail rates and avoid shipping delays if it is to maintain its market share. With the labor situation now more stable in Australia and Poland, buyers appear to be returning to these sources as they contract for future shipments. Poland, driven by the need for hard currency, is alleged to be selling below cost, which makes it attractive to the market. Meanwhile, the differential between U.S. and Australian coal, delivered in Japan, has dropped to $10 a ton (Anon., 1982a,b; 1983a,b).

As a result of a recent 18 percent price reduction, Australian metallurgical coal is now available at the port for $50-55 per metric ton ($45-50 per short ton) and costs $10-12 per metric ton ($9-11 per short ton) for shipment to Japan (Snow, 1983). Canada has reduced its price 25 percent to $48 per short ton to win a Japanese contract. In order to gain Japanese orders, some Virginia producers have reduced their mine price by $12-16 per ton to $32 per ton in order to compete with Australia (Virginia Coal Council, 1983). Current rail transportation costs are about $15 per ton from Virginia coal fields to Lamberts Point, with a loading charge of $.50 per ton and a shipping cost of $12.50 per ton to Tokyo. Australian coal costs $54-61 per short ton delivered in Japan, while Virgina coal costs approximately $59 per short ton (Cahill, 1983).

As noted previously, Virginia is also one of the high-cost (marginal) producers in the central Appalachian region. It has been reported that even when the Virginia producers match the mine-mouth price of coal from West Virginia or eastern Kentucky, they are still not completely competitive because transportation rates within Virginia may be $3 per ton higher than those from the other states (Virginia Coal Council, 1983). Rates among railroads are highly competitive, but to gain the best rail rates customers must often change suppliers depending on which railroad has the best rate. The recent steam coal contract incident involving New England Electric demonstrated its need to switch both railroad and coal supplier to achieve lower transportation rates. The contract was finally negotiated with a return to the original coal supplier when its servicing railroad lowered rates by $3 per ton (Bacon, 1982c). The delivered price of coal depends on costs set by both the supplier and its transporter. But the transportation system which serves the supplier, or group of suppliers, has a profound impact on that supplier's future since it is often the only transportation available and can set its rates without regard to supplier competition.

EFFECT OF A COAL SLURRY PIPELINE

Pending federal legislation that might have a significant impact on the competitiveness of Virginia coal are Coal Slurry Pipeline Bills S267, and HR1010 (U.S. Congress, 1983b). If passed, the final bill would permit right of eminent domain for interstate coal slurry pipelines, overriding Virginia's statute prohibiting such rights. This would apply if a pipeline were built in Kentucky or West Virginia and traveled through Virginia to Hampton Roads. Such a pipeline might result in a $5-10 a ton cost advantage to Kentucky or West Virginia coal, which could then invade Virginia's coal markets -- both domestic and foreign, accounting for about 10 million tons per year. West Virginia is studying several such pipeline routes (Smith, 1983).

Considerable debate has been generated regarding the potential adverse effect of a Virginia coal slurry pipeline on Virginia's coal industry and railroads. The facts are that CSX transports little Virginia coal to Hampton Roads, and 90 percent of N&W coal is metallurgical coal which probably cannot be carried by slurry due to larger coal-size requirements. Only 22.8 percent of the coal exported from Hampton Roads in 1982 was Virginia coal, most came from West Virginia and Kentucky (Hunter, 1983). Most of the Virginia coal which could be carried by a slurry pipeline would be met quality coal seeking a steam coal market (new or additional sales) either overseas or in New England. And, 3.7-6 million tons (9-15 percent of Virginia's current production) could be used, or has a potential to be used, by Vepco. Thus, the coal moved would represent almost entirely new or additional coal sales with little or no adverse effect on Virginia's coal industries or N&W's existing businesses.

The Virginia Coal Slurry Pipeline study (Yucel, 1982a,b), conducted under the Center's supervision and rated as sound engineering research by both Bechtel and Boeing, lacks only the calculation which would add profits and taxes to determine rates. In spite of comments to the contrary, all of the other costs are there, including gathering-by-truck and discharge-water purification, but focus on a single point of delivery such as Lamberts Point.

If we take Yucel's study numbers for a pipeline throughput of 10 and 25 million tons per year with a 10 percent money cost, 50 percent profit before taxes, and a 40 percent tax rate, the following rates result:

10 million tons per year amounts to $7.15 to $8.83 per ton (1981 dollars).
25 million tons per year amounts to $5.33 to $6.73 per ton (1981 dollars).

The rate range depends upon which route from southwest Virginia is selected.

The railroad rate from southwest Virginia to Lamberts Point was reported at a recent Virginia Coal Council meeting (Virginia Coal Council, 1983) as being $15.72 per ton. The differences from that compared to the 10-25 million ton-per-year pipeline rates is $6.89 to $10.39 per ton, which is approximately the same as the values noted in the OTA study.

In addition, there is a study by Aude, Wasp and Thompson (1979) which estimates coal transportation cost-inflation, and notes that pipeline costs are 75 percent capital costs compared to 25 percent for railroads. Based on this analysis, the study projects inflation rates for pipelines at 2.69 percent per year and at 6.79 percent per year for railroads. Therefore, even if the coal transportation costs for railroads and pipelines are exactly alike today (assume $8 per ton), by the year 2000 the per-ton cost differential becomes $24.40 minus $12.56, or $11.84.

A Virginia coal slurry pipeline would have little impact on the United States' share of the world coal market (and the central Appalachian region's share). As the marginal producer, the United States sets the world price for coal based on its higher costs. Coal from Australia, South Africa and Poland is significantly less expensive than U.S. coal (Anon., 1982b; 1983a,b). Hence, if U.S. prices were dropped $12 to 16 per ton (as they were recently), the other producers could easily follow (as they did) and still earn a profit (Virginia Coal Council, 1983). Thus, a drop in price of $5 to 10 per ton due to a coal slurry pipeline would not provide the United States with a larger share of the world coal market, but it would make the United States' share more profitable.

However, if Virginia's delivered coal price were reduced $5 to 10 per ton, due to a Virginia coal slurry pipeline, it would probably gain for Virginia a larger share of the coal market now served by the central Appalachian region (i.e., increase its share of the Hampton Roads exports, now 22.8 percent, to as much as 50 percent, because its delivered price would be lower than coal from eastern Kentucky or southern West Virginia). Eastern Kentucky might match this reduction since it has the lowest coal cost and could truck coal from eastern Kentucky mines to the Virginia pipeline. It is doubtful if West Virginia could match this reduction. Hampton Roads might gain a larger portion of the total export market, and domestic shipments out of Hampton Roads could amount to an additional 2 to 4 million tons per year. This additional market might increase the useful capacity of the pipeline from 10 to 25 million tons per year.

POTENTIAL IMPACTS OF AN INCREASE IN COAL DEMAND BASED ON COAL DELIVERED COSTS

Although further detailed studies will be required when a specific pipeline proposal is made, there are numerous reasons why a coal slurry pipeline could bring increased output, employment, and income to Virginia's coal producing areas (Campbell and Katell, 1975).

Lower costs could make Virginia coal more competitive, relative to eastern Kentucky and southern West Virginia, and amplify the expected growth in coal demand which would create more mining, coal-related jobs, and bring additional income to Virginia's coal mining areas (Larwood and Benson, 1976).

A lower delivered price, and the expectation of stabilized transportation costs, might make electric utilities more willing to use coal. And, lower transportation costs would probably tend to increase Virginia's share of the utility coal market. Utilities now account for approximately 80 percent of domestic coal use, and their future energy needs represent a vast potential market (Kearny, 1981).

An indication of the benefits to coal-producing areas from a coal pipeline is provided by a 1980 study (Nat. Econ. Res. Assoc., 1980) of the proposed Coalstream Pipeline from Illinois, Kentucky, West Virginia and Tennessee, to Georgia and Florida. The Coalstream Pipeline will have an annual capacity of 30 million tons compared with a maximum of 27.6 million tons (25 million metric tons) for the Virginia pipeline. The study found that the development of the Coalstream Pipeline could lead to:

* the production of 17.3 million tons of additional coal,
* the addition of $432 million to the economies of the coal-producing areas, and
* the creation of 5,200 new jobs for miners.

SMALL PRODUCERS

Expanded coal production could bring benefits to small coal producers as well as large. Traditionally the small independents thrive in expanding markets, and they could deliver coal to pipeline or rail by truck as they do now. A pipeline would enable those coal producers, too small to supply a unit train, to compete with larger mines on the delivered price of coal.

Small coal producers will also be protected by common carrier provisions, which means that the carrier operator should not give undue preference to any one customer. This obligation extends to the securing of contracts for a portion of the pipeline's capacity before construction, during operation, and all the way to the sale of uncommitted capacity.

Although oil and gas pipelines carry only one commodity, they have operated for years as common carriers. Coal pipelines will operate as common carriers in the same fashion, providing a service, subject only to capacity limitations to shippers who are ready, willing and able to ship coal along the pipeline route.

EFFECT OF SULFUR DIOXIDE EMISSION CONTROLS

A factor which might increase the use of Virginia coal is the clean air legislation, now being considered in the U.S. Congress, which would require electric utilities to reduce sulfur dioxide emissions by 10 million tons per year (S145, HR132, U.S. Congress, 1983a).

One of the ways to meet the proposed legislation is to buy from coal producers whose product is low in sulfur content. Much of the low-sulfur steam coal produced in the United States is sub-bituminous coal which eastern utilities can't use efficiently without a boiler retrofit (OTA, 1982). Therefore, utilities may find it more attractive to switch to blended low-sulfur met coal rather than to depend exclusively on scrubbers for flue gas desulfurization, or a boiler retrofit.

East of the Mississippi River there are 50 large coal-burning utilities using high sulfur coal with more than 1.2 pounds of sulfur dioxide per million Btu, the proposed emission control standard. The demand for coal by eastern U.S. utilities in 1980 was 232 million tons with Virginia utilities consuming 5.2 million tons (EIA, 1982c). Eastern utilities are expected to increase this demand by 10 million tons in 1984 with Virginia utilities increasing their consumption by 3.5 million tons. By the year 2000, eastern utilities are expected to use 250 million tons, an addition of 18 million tons.

In the same geographical area there are 28 billion tons of coal reserves containing lower amounts of sulfur than that prescribed by the emission control standard. Virginia has 2.253 billion tons of these. Other principal reserves are in southern West Virginia, eastern Kentucky and Alabama. There are also small amounts in Pennsylvania, Indiana and Tennessee, but essentially none in Illinois, Michigan, Ohio, Maryland and North Carolina (EIA, 1981).

Eastern low-sulfur coal reserves of 28 billion tons could supply eastern utilities with low-sulfur coal for 100 years -- provided the delivered price is competitive with coal from the northern plains states and with the cost of installing and operating scrubbers. Virginia could supply its electric utilities with low-sulfur coal, and provide an additional 90 million tons per year for eastern utilities for a period of 100 years.

Thomasian, 1982; OTA, 1982; Parker, 1982, and others have estimated a 60-70 percent production increase of low-sulfur coal in central Appalachia if the proposed clean air legislation is enacted. If this estimate is correct and the legislation passes, an additional 21 million tons of low-sulfur, low-ash met coal might be produced in Virginia and sold to the electric utilities for steam coal blending. This amount is in addition to the possible 10 million tons of Virginia met coal which might also be exported for steam coal use and the 9 million tons of steam coal produced in 1980. This amounts to 40 million tons which might be added to the projected steel market requirement of about 39 million tons. However, for political and economic reasons[4], total expected tonnages may not develop. The projections used in this report do not include the impact of a coal slurry pipeline, which might offset the political and economic effects.

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[4] The Clean Air Act permits a state to use its own coal, even if it is high sulfur, if the switch to compliance coal causes economic disruption as determined by the governor of that state. Ohio has used this provision.

RECENT TRENDS IN VIRGINA'S COAL PRODUCTION

In 1982, Virginia's coal production dropped to 37.2 million tons from 41.9 million tons in 1981, a reduction of 11.2 percent, while U.S. coal production remained stable at 824 million tons. During the first five months of 1983, Virginia's coal production sank 25 percent compared to the first five months of 1982, and U.S. coal production declined 15 percent. During this same period, Virginia's share of U.S. coal production dropped from 5.12 percent to 4.23 percent, a loss of nearly 1 percent of market share (EIA, 1982a; 1983a,b).

Hampton Roads terminals exported 53 million tons in 1982, up 11.3 percent from the 47.3 million tons exported in 1981. However, during 1982, Virginia-produced coal exported through Hampton Roads dropped 6.9 percent from 13.0 to 12.1 million tons. All of this coal was transported by the Norfolk Southern Corporation, which increased its haulings for foreign export from 33.6 million tons in 1981 to 34.6 million tons in 1982. Of this, eastern Kentucky coal gained 4.6 million tons reaching 9.9 million tons in 1982. Concurrently, domestic coal traffic from Hampton Roads increased from 2.4 million tons in 1981 to 4 million tons in 1982 (EIA, 1983b; Hunter, 1983).

The above information suggests that the Virginia coal industry is not maintaining its production share of the U.S., central Appalachian, or Hampton Roads market activity. The loss, it seems, results from the lower competitive cost of eastern Kentucky coal. If this trend continues, the future for Virginia's coal industry looks very grim, indeed.

To reverse this trend, the delivered costs of Virginia-mined coal must be reduced to meet the competition from eastern Kentucky. Several Virginia coal producers (Paramont and Westmoreland, Virginia Coal Council, 1983) maintain that when they match the mine-mouth prices in eastern Kentucky, they are beaten by lower competitive transportation costs. Significantly, the railroads are attracted to eastern Kentucky coal because of its larger reserves, larger production capacity, lower mining costs, lower transportation costs and railroad-owned reserves.

It is believed that Norfolk Southern can provide faster turn-around time for ships at Hampton Roads than can CSX. Faster turn-around time reduces demurrage and thus lowers ship transportation costs. If this is true, Norfolk Southern may gain export market-share from CSX at Hampton Roads. However, CSX is still the largest coal transporter in the United States, and may be capable of meeting its transportation competition (Anon., 1983e).

SUMMARY

Virginia's coal sales have been largely for metallurgical (coking) applications.

The met coal market is facing a serious decline. Those suppliers with long-term contracts believe they will not be affected unless force majeure (coercive power) is imposed. Long-term projections, based on a worldwide recovery of the steel industry and the changing technology and economics of steel making, suggest that future sales will be flat. Based on studies of market trade-preferences, evidence suggests that Australia will displace the United States as the leading exporter of met coal. The possible requirement that U.S. coal-burning utilities reduce sulfur dioxide effluents may lead to met coal being burned in steam boilers as a measure to avoid installing the more costly flue-gas scrubbers. This requirement, if it becomes law, would improve sales prospects for the central Appalachian coal market. Coal slurries to replace fuel oil in commerical and utility boilers and clean fine coal for chemical feed stocks are other potential new markets totaling 200 million tons per year.

In any event, the Virginia coal market is presently an erratic buyers market with more production capacity than demand, and a growing sensitivity to prices resulting from the unstable world economic situation. Our coal suppliers, because of rising mine, railroad, port, and shipping costs, now charge the highest worldwide delivery prices which will make Virginia a residual supplier and possibly vulnerable to more foreign imports.

A coal slurry pipeline which will reduce the delivered cost of Virginia's coal and make it more competitive with eastern Kentucky and southern West Virginia coal, of similar quality, will assist the state in maintaining its market share as the market recovers. Although it will not increase the world-market share exported from Hampton Roads, it may increase Virginia's share of that market from 22.8 percent to 50 percent.

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Production (Million Tons) and Regional Percentages

	1980	1981	1982	1983 (21 wks)
United States	829.7	823.8	833.4	289.9
Central Appalachia*	271.8	272.7	277.3	101.3
(Percent of U.S. production)	32.8%	33.1%	33.3%	34.9%
Eastern Kentucky	109.2	117.9	111.4	40.4
Percent of central Appalachian production	40.2%	43.2%	40.2%	39.9%
Virginia	41.0	42.0	37.2	13.4
Percent of central Appalachian production	15.1%	15.4%	13.4%	13.2%
West Virginia	121.6	112.8	128.8	46.4
Percent of central Appalachian production	44.7%	41.4%	46.4%	46.9%

(Source: Energy Information Admin. Weekly Coal Reports DOE/EIA 83-1 to 21)

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*Central Appalachia includes eastern Kentucky, Virginia and West Virginia.

Senator **Warner**. Thank you very much. We will not have any questions at th is time, since we have to move right along. Its been helpful to set the framework.

And we now have a witness who hopefully can help shed some light on the questions posed about the problems with the use of coal. As we are sitting here this week, the President and his advisors are working on the problem of acid rain and are looking to schedule, perhaps by mid-September, some statement by President Reagan. But I'll leave that up to you Frank.

STATEMENT OF FRANK T. PRINCIOTTA, DIRECTOR, INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY, ENVIRONMENTAL PROTECTION AGENCY

Mr. **Princiotta**. The invitation was sent to Mr. Ruckelshaus and due to a conflict he asked me to substitute for him. My name is Frank Princiotta. I am the Director of the Industrial Envrionmental Research Laboratory, EPA's Laboratory for Research, Triangle Park, NC. I appreciate the opportunity to discuss enhanced coal technology.

Perhaps I can refer immediately, Senator Warner, to your question about Mr. Ruckelshaus' recommendation on acid rain and I can tell you this, its not in the testimony.

Senator **Warner**. You say it is or it isn't?

Mr. **Princiotta**. It is not, specifically. But I will just refer to that briefly, if I could, Once Mr. Ruckelshaus took over EPA, his first task was to set up an EPA acid rain task force of many members within the Agency. Over a period of time this task force has been doing quite a bit of staff work and learning all we know of acid rain and its problems and the many scientific problems which are unresolved. The task force is also looking at various control options. Any my understanding is that Mr. Ruckelshaus received a report on that just last week. My understanding is that probably sometime late in September, the Agency and Mr. Ruckelshaus will make specific recommendations related to acid rain control.

Senator **Warner**. I think that's very important. We might review that once more for our group. I met with Mr. Ruckelshaus twice in the last 30 days. Senator Byrd of West Virginia, Senator Ford of Kentucky, myself, Senator Percy, Senator Heinz—those of us that are of the coal caucus are periodically reviewing the administration's handling of the issue and we have urged Mr. Ruckelshaus to proceed slowly and hopefully allow Congress to return from its recess before any final decisions are made. The impact was laid out by our first distinguished witness, Mr. Blackmore, of one of the bills introduced to tackle the acid rain problem and which is now pending before the Senate and House. The President and this staff will be meeting at staff level in August, I am told. And then, Mr. Ruckelshaus and the President will be working during September on this issue. So it is possible that a presidential statement on this problem may be issued, as you say, in the late part of September. Thank You.

Mr. **Princiotta**. EPA agrees that coal is a vital energy source in the United States. The mining, transportation, and conversion of coal to useful energy are critical to all elements of the Nation's economy. You have heard much of this and will hear more of it and its certainly true. But we need to recognize that coal is a relatively dirty fuel if not handled properly. The major pollutants associated with the production of coal include sulfur dioxide [SO_2], nitrous oxides, and particulate matter. With the technology that is currently available, however, it is possible to effectively control the emissions of SO_2 and particulate matter—but at reasonably high costs. Thus the major business is not "can we control the release of these pollutants?" but "how can we reduce the compliance cost of controlling SO_2 and particulate matter emitted by burning coal?" For NO_x, current controls are relatively ineffective but combustion modification approaches are emerging which are both effective and relatively low in cost.

The balance of my statement will briefly discuss the state-of-the-art of coal cleanup technologies and important technologies for each of the major pollutants.

Sulfur oxide control is probably the most important pollutant in the terms of the question of control and the cost limitations in the combustion of coal. Currently, about 25 million tons of SO_2 are emitted into the atmosphere by various utility and industrial sources in the United States each year. Sulfur dioxide is an important air pollutant capable of inducing respiratory disorders particularly among susceptible individuals. It is also the major precursor associated with acid precipitation, visibility deterioration and inhalable particulate matter. The main approaches to reducing emissions of sulfur oxides from coal combustion are removing sulfur from the coal which you heard quite a bit about this morning, capturing the sulfur oxides during the combustion process—emission and vapor, and the removing or scrubbing of sulfur oxides from the combustion flue gas. Of these methods, flue gas scrubbing (also called flue gas desulfurization—FGD) is the only technology that is used commercially on a wide scale at electric utility plants. My detailed statement provides more information about gas and sulfurization technologies.

Since the early 1970's, EPA's research program has played a critical role in upgrading the performance and reliabillity of the dominant lime and limestone scrubbing technology. And quite frankly, if any acid rain legislation were proposed, clearly lime and limestone scrubbing would be the new technology. EPA has recently demonstrated the ability of organic acid additives to further improve performance and reliability over state-of-the-art limestone scrubbers. Research efforts continue to seek lower cost throwaway and saleable product systems.

In terms of physical coal cleaning, we have heard quite a bit about that from Mr. Blackmore and I won't belabor that issue. However, I would like to point out that unfortunately such a technology is a relatively inefficient way of removing sulfur and typically it will only reduce it by 10 to 30 percent, depending on the specific coal.

Moving through nitrogen oxide control, the EPA recently estimated that about 20 million tons of nitrogen oxides were emitted from stationary and mobile sources in the United States in 1981. Coal firing in utility boilers accounted for nearly 30 percent of these emissions. Nitrogen oxides, principally nitric oxide and nitrogen dioxide, are air pollutants having potential for adverse human health and welfare effects. In addition to the direct health effects of NO_2, NO_x reacts with other atmospheric pollutants (for example hydrocarbons) to form photochemical oxidants, a major air pollutant. More recent studies also indicate that NO_x may be a significant contributor to acid precipitation.

A first generation burner technology has already been incorporated into commercial application and was the basis for reducing the New Source Performance Standard for electric utility plants for nitric oxide in 1979. Capital costs are estimated at about $5 a kilowatt. Such burners are capable of burning coal with about 30 to 40 percent less emission.

The EPA builds research programs exploring research to reduce NO_x even further, particularly for new boilers. The most promising technique is second generation low NO_x burners.

Two such concepts have been developed by EPA. They are the distributed mixing burner (for wall-fired boilers) and the rich fireball (for tangentially fired boilers). Experimentally these techniques have shown the potential to reduce NO_x above and beyond current techniques by more than 50 percent. The distributed mixing burner has been installed on an industrial-sized boiler and has achieved up to 70 percent NO_x reduction under optimal conditions. The rich fireball, installed on a 400 megawatt utility boiler, has achieved up to 50-percent reduction in NO_x emission in a long-term operation. For new boilers, NO_x reductions greater than 50 percent from current NSPS should be achievable.

Let me talk just briefly about combined nitrous oxide and sulfur oxide control. In addition to separate controls for SO_x and NO_x, several control technologies simultaneously remove these pollutants. In general, these combined technologies are developmental and not fully commercialized. Such systems include limestone injection through multistage burners, the acronym for this is LIMB, a retrofitable technology, and fluidized bed combustion, FBC, a complete coal combustion system primarily for new applications.

The LIMB technology evolved from the EPA-sponsored low NO_x coal burner development work. A limited series of small pilot-scale experiment showed that up to 70 percent sulfur oxide reduction could be achieved with reasonable amounts of sorbent added in the low NO_x burner flame zone. These techniques are quite inexpensive compared to scrubbers. Typically the capital cost might be one-fifth that of the comparable coal gas desulfurization. I might add that the EPA appropriations bill for fiscal year 1984 added $5 million with the aim of developing and perhaps ultimately administering them for multistage burners to be used in accelerating this technology and possibly demonstrating this technology. I think the interest there was primarily the potential of this technology as a relatively low cost acid rain recommended approach although it should be pointed out that this technology is not likely to be commercially available until the late 1980's.

In terms of particulate matter, the uncombustible portion of the coal is emitted mostly as particulate matter, also called fly ash. Particulate matter, especially the smaller particles, is a major air pollutant which can cause both health and environmental impacts. Conventional electrostatic precipitators and fabric filters are technologies capable of efficient particulate control, but capital and operation and maintenance costs can be quite high, and compliance violations are prevelant. Although electrostatic precipitators have dominated the utility market in the past, current trends show that ESP's, electrostatic precipitators, and fabric filters will share future markets. The major problems with these systems are their high costs and their design operational uncertainties. The EPA research program is designed to prove costs can be reduced by 50 percent and to eliminate design and operational uncertainties. I'm happy to say we've come a long way toward meeting these ambitious goals. For example, we've developed an advanced electrostatic precipitators system based on precharging the dust. Cost estimates show that the precharger system can reduce the capital costs by 30 to 40 percent. We are also looking at relatively simply modifications to ESP discharge electrodes which could provide major cost savings for both new and retrofit applications.

The most promising idea for reducing the costs of fabric filters is electrostatic enhancement of the filters. Our research to date shows that we can reduce both the capital and operating costs by 30 to 60 percent with such electrostatic enhancement. The concept that EPA is evaluating involves placing a strong electric field in the fabric yielding higher allowable gas flow rates, thereby allowing a drastic reduction in facility size.

In conclusion, I'd like to thank you for this opportunity to discuss this highly technical but important subject. In closing, we believe cost effective and reliable control technology applied to coal combustion can bridge the gap between large scale use of potential coal reserves and environmental protection. Thank you.

[The prepared statement of Mr. Princiotta follows:]

STATEMENT OF

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BEFORE THE

SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

BLACKSBURG, VIRGINIA
AUGUST 9, 1983

Good Morning, Mr. Chairman, and members of the Subcommittee. My name is Frank Princiotta. I am the Director of the Industrial Environmental Research Laboratory of the Environmental Protection Agency at Research Triangle Park. We appreciate the opportunity to meet with you today to discuss Enhanced Coal Technology.

Coal is a vital energy source in the United States. The mining, transportation, and conversion of coal to useful energy are critical segments of the Nation's economy. More than 50 percent of the total electricity produced in the United States is generated from coal. Abundant reserves make the United States self-sufficient in coal for the foreseeable future.

The major pollutants resulting from the combustion of coal include sulfur dioxide (SO_2), nitrogen oxide (NO_x), and particulate matter. With technology that is commercially available, it is possible to effectively control the emissions of SO_2 and particulate matter - but at great expense. Thus, the major research question is not "can we control the release of these pollutants?" but "how can we reduce the compliance cost of controlling SO_2, and particulate matter emitted by burning coal?" For NO_x, current controls are relatively ineffective but combustion modification approaches are emerging which are both effective and relatively low in cost.

The balance of my statement dicusses the state-of-the-art of coal cleanup technologies and important emerging technologies for each major air pollutant.

Sulfur Oxide Control

Currently, about 25 million tons of SO_2 are emitted into the atmosphere by various utility and industrial sources in the United States each year. Sulfur dioxide is an important air pollutant capable of inducing respiratory disorders particularly among susceptible individuals. It is also the major precursor associated with acid precipitation, visibility deterioration and inhalable particulate matter. The main approaches to reducing emissions of sulfur oxides from coal combustion are removing sulfur from the coal, capturing the sulfur oxides during the combustion process, and removing or scrubbing the sulfur oxides from the combustion flue gas. Of these methods, flue gas scrubbing (also called flue gas desulfurization - FGD) is the only technology that is used commercially on a wide scale at electric utility plants. To date, more than 100 FGD installations scrub flue gas on about 44,000 megawatts of electrical generating capacity. If we add the planned FGD capacity, we expect over 200 utility FGD units to control over 100,000 megawatts of generating capacity in the United States by the turn of the century.

FGD processes can be classified as those that produce a throwaway product or waste versus those that produce a saleable product such as sulfur or sulfuric acid. Almost all current and planned FGD installations are the throwaway type because this is more economical. The most common FGD processes that produce a throwaway product are those scrubbers employing lime or limestone as the alkali reagent. This reagent reacts with the acidic SO_2 yielding throwaway insoluble calcium salts. The processes that produce saleable products are more complicated, and expensive.

The cost of current FGD technology is high in terms of total dollars and represents the most expensive air pollution control device for coal combustors. Capital costs for FGD are typically $200 per installed kilowatt, compared to about $1000/kw for a new coal-fired electric plant, including FGD.

Since the early 1970's, EPA's research program has played a critical role in upgrading the performance and reliability of the dominant lime and limestone scrubbing technology. EPA has recently demonstrated the ability of organic acid additives to further improve performance and reliability over state-of-the-art limestone scrubbers. Research efforts continue to seek lower cost throwaway and saleable product systems.

Physical coal cleaning represents an alternative and/or supplemental sulfur oxide control approach. Coal is physically cleaned - a process sometimes called washing - by crushing it until some of its mineral impurities, containing sulfur, are released. Conventional physical coal cleaning processes can reduce the potential sulfur emission from the combustion of coal typically by only 10 to 30 percent, depending on the specific coal.

Approximately 30 percent of all utility coals are currently cleaned. Current practices reduce the potential annual SO_2 emission from coal production by 1.8 million tons. Conventional coal cleaning processes increase the cost of coal by 15 to 30 percent. However, a part of these costs are offset by reduction in transportation, boiler operations, and flue gas cleaning costs.

Nitrogen Oxide Control

EPA recently estimated that about 20 million tons of nitrogen oxides were emitted from stationary and mobile sources in the United States in 1981. Coal firing in utility boilers accounted for nearly 30 percent of these emissions. Nitrogen oxides (NO_x), principally nitric oxide (NO) and nitrogen dioxide (NO_2), are air pollutants having potential for adverse human health and welfare effects. In addition to the direct health effects of NO_2, NO_x reacts with other atmospheric pollutants (e.g., hydrocarbons) to form photochemical oxidants, a major air pollutant. More recent studies also indicate that NO_x may be a significant contributor to acid precipitation.

For existing coal-fired boilers, one of the more effective NO_x reduction techniques is to reduce the level of excess air supplied to the burners. This technique, referred to as low excess air firing, can reduce NO_x emissions by as much as 50 percent and has the side benefit of increased boiler efficiency. All boilers, however, do not have sufficient flexibility to achieve this level of emission reduction via low excess air.

A variation of the low excess air approach is to operate the lower levels of burners (utility boilers have multiple rows of burners located on the boiler's vertical walls) at the lowest excess air level possible and to provide additional air in the upper regions of the boiler. EPA field tests of 22 pulverized coal-fired boilers using these combustion modifications resulted in NO_x emission reductions ranging from 12 to 62 percent (the average reduction for all units was 37 percent). Capital costs average only about $2/kw.

The major thrust of EPA's NO_x reduction program is to develop the technology for new low NO_x burners which may either be retrofitted to existing boilers or incorporated into new designs. These burners reduce NO_x by delaying the rate of mixing between fuel and air, thereby limiting the availability of free oxygen in the initial burning process. First generation burner technology has already been incorporated into commercial application and was the basis for reducing the New Source Performance Standard (NSPS) for NO_x in 1979 for coal-fired utility boilers. Capital costs are estimated at about $5/kw.

While conventional combustion modifications have been used to achieve emissions below NSPS levels, we are exploring advanced combustion techniques to reduce NO_x even further, particularly for new boilers. The most promising technique is second generation low NO_x burners.

Two such concepts developed under EPA sponsorship are the distributed mixing burner (for wall-fired boilers) and the rich fireball (for tangentially fired boilers). Experimentally these techniques have shown the potential to reduce NO_x emission by more than 50 percent form current NSPS levels for pulverized coal-fired units. The distributed mixing burner has been installed on an industrial-sized boiler (22MW) and has achieved up to 70 percent NO_x reductions under optimal conditions. The rich fireball, installed on a 400MW utility boiler, has achieved up to 50 percent reduction in NO_x emissions in long-term operation. For new boilers, NO_x reductions greater than 50 percent from current NSPS should be achievable.

Combined SO_x/NO_x Control

In addition to separate controls for SO_x and NO_x, several control technologies simultaneously remove SO_x and NO_x. In general, these combined technologies are developmental and not fully commercialized. Such systems include limestone injection through multistage burners (LIMB) - a retrofitable technology, and fluidized bed combustion (FBC) - a complete coal combustion system for new applications.

For the long-term, several advanced combined flue gas treatment technologies are being developed by the Department of Energy. These include an electron beam technology and an advanced copper oxide reactor, both of which simultaneously remove SO_x and NO_x from flue gases.

The LIMB technology evolved from the EPA-sponsored low NO_x coal burner development work. It was recognized that the condition which resulted in reduced NO_x might also promote capture of sulfur compounds by adding sorbents (e.g., limestone). A limited series of small pilot-scale experiments showed that up to 70 percent sulfur capture could be achieved with reasonable amounts of sorbent added in the low NO_x burner flame zone. Application of the technique to boilers would be a relatively simple way to reduce SO_2 emissions. Preliminary estimates indicate capital costs of only about 20 percent of the cost of FGD. With increased interest in low-cost control technology for the major acid rain precursors (SO_x and NO_x), in 1981 the EPA launched the LIMB R&D program for pulverized coal-fired boilers. The primary objectives of the EPA LIMB/low NO_x program are: 1) for retrofit, 50-60 percent reduction of both SO_x and NO_x from uncontrolled levels; 2) for new systems, 70-80 percent NO_x reduction and 70-90 percent SO_x removal from uncontrolled levels; and 3) cost reductions of $50-$150/kw less than alternate technologies, such as FGD.

Fluidized-bed combustion (FBC) is another technology that simultaneously reduces emissions of sulfur and nitrogen oxides. FBC involves the burning of coal in a bed of limestone that has been fluidized with the combustion air. The limestone in the bed reacts with the SO_2 released during the combustion of the coal and forms a solid material which can be disposed of as a dry solid waste along with the coal ash. Several successful industrial boiler FBC units are in operation at this time. Although EPA does not have an active R&D program for FBC, we are monitoring the status of this emerging technology.

Particulate Matter Control Technology

The uncombustible portion of the coal is emitted mostly as particulate matter, also called fly ash. Particulate matter (especially the smaller particles) is a major air pollutant which can cause both health and environmental impacts. Conventional electrostatic precipitators and fabric filters are technologies capable of efficient particulate control, but capital and operation and maintenance costs can be quite high ($50-$60/kw), and compliance violations are prevalent. Although electrostatic precipitators have dominated the utility market in the past, current trends show that the electrostatic precipitators and fabric filters will share future markets. The state-of-the-art of these technologies is somewhat provincial as it has traditionally been difficult to make advances in these arts.

Electrostatic precipitators (ESP) are the most commonly used device for controlling particulate emissions from coal combustions. An ESP is basically a large box with many rows of metal plates parallel to the gas flow. High voltage is applied to wires located between these collection plates. The high voltage produces an electric discharge (corona) which puts an electric charge on the particles. The charged particles then are forced to the plates by the electric field that exists between the wires and the plates.

Fabric filters, the major alternative to ESPs, can be looked at as very large vacuum cleaners. The dirty air is forced through a bag which removes the dust. For most dusts the fabric filtration process is very efficient. However, current technology fabric filters are very large (several thousand bags are needed for a power plant) and expensive, and have high operating and maintenance costs.

The major problems with both electrostatic precipitators and fabric filters are their high costs and their design and operational uncertainties. Our research program is designed to prove costs can be reduced by 50 percent and to eliminate these design and operational uncertainties. I am happy to say we have come a long way towards meeting these ambitious goals. We have developed an advanced electrostatic precipitator system based on precharging the dust. Cost estimates show that the precharger system can reduce the capital costs by 30 to 40 percent. We are also looking at relatively simple modifications to the ESP discharge electrodes which could provide major cost savings for both new and retrofit applications.

The most promising idea for reducing the costs of fabric filters is electrostatic enhancement of the filters. Our research to date shows that we can reduce both the capital and operating costs of fabric filters by 30 to 60 percent with electrostatic enhancement. The concept that EPA is evaluating involves placing a strong electric field in the fabric yielding higher allowable gas flow rates, thereby allowing a drastic reduction in the required facility size.

Combined SO_x/Particle Control

On the horizon, an existing area of particle research is finding ways to use existing particle control devices to remove SO_x in retrofit situations. This concept has the potential to result in a low-cost technology that will allow an existing plant to meet particulate emission requirements and also achieve up to a 50 percent reduction in SO_x emissions. This work is just starting along with assessing the synergistic advantages of combinations of SO_x-NO_x-and particle control technologies in least cost, highly reliable integrated systems.

Conclusion

Thank you for this opportunity to discuss this highly technical but important subject. In closing, we believe cost effective and reliable control technology applied to coal combustion can bridge the gap between large scale use of potential coal reserves and environmental protection. If you have any questions I would be happy to answer them at this time.

Senator **Warner**. The question is of economics. Just how much added cost this industry, which is now pressed, can bear in order to meet the objectives, laudatory though they may be for the purposes of environmental control. Can you share with us, on an informal basis, the thinking at staff level with respect to this problem of acid rain and some of the recommendations that are in mind?

Mr. **Princiotta**. I can say that Mr. Ruckelshaus has been looking at a wide range of applications from modest control all the way to higher reductions associated with some of the bills that have been proposed. I honestly think that his mind is completely open on the subject. I think he is well aware now of the complexity of this issue. And I am personally aware, based on my participation in his task force, that the issue regarding the impact on the electric utility industry and the coal mining industry will be addressed very carefully by Mr. Ruckelshaus before he makes any of his recommendations.

Senator **Warner**. So there's a very careful study of the economic impact that is going on at the same time that we are analyzing the scientific means in critical detail?

Mr. **Princiotta**. Yes. In fact, for every one of the options that we have evaluated as a taskforce, there has been an economic analysis associated with it. Quite frankly, the costs can be quite high.

Senator **Warner**. In the linkage of that chain of evidence between acid rain effects and the origins, where are we in terms of strengthening the case indicting coal or is it laying flat? How is this study moving?

Mr. **Princiotta**. There is probably no single one expert in this field since there are so many different disciplines involved. I am a specialist, primarily, in controlled technology. I can say this, though, there is a very active interagency acid rain research program. I am one of the task force chairmen for controlled technology, so I have some opportunity to find out what is going on in the program area. And I think there's probably almost a consensus that there has been some damage from certain lakes in the Appalachia area.

Senator **Warner**. Directly attributable to coal?

Mr. **Princiotta**. I think the case is not quite that clear, but I think most of the experts would agree its attributable to sulfuric acid and nitric acid both of which can be produced in the atmosphere, both SO_2 and nitrous oxide, both of which result from the combustion of coal.

Senator **Warner**. So, in layman's terms, the jury is still out on this and coal still has not been convicted. Is that correct?

Mr. **Princiotta**. Well, I think maybe its a bit more complicated than that. I think there's a general feeling in the scientific community that coal is a major element of the acid rain problem. Frankly, I don't think the magnitude of the acid rain problem is completely identifiable. Studies have been done for example on what, if any, the effects of acid rain may be on forests, agricultural production. I think most of the impacts that are fairly well documented are associated with the surface of lakes.

Senator **Warner**. That is the clearest evidence of the detrimental effects of it.

Dr. Hibbard, I read your face and I see your head nodding. This is such an important subject, acid rain. I would hope that perhaps you can shed your thoughts on it, for a moment?

Dr. HIBBARD. My problem is that I think pointing the finger at coal is a little premature. There is acid rain in California for example, and they burn no coal in California. There are local sources, automobiles, diesels, apartment houses. And the thing that concerns me about the present approach is the academe study, for example, cannot distinguish between local and long distance sources. In all the media information, they say very clearly there is no reason to suspect that reducing the coal burning in the Ohio Valley is going to solve the problem of acid rain in New England. Second, there's just a recent article, a recent study which points out that the lake problem is more related to the geology of the soils surrounding the lake then it is to acid rain. Neutral rain, as its described, has a PH of 5.6 and that's acid, by any stretch of the imagination. If the rain fell completely neutral, the problem would still exist. So there's severe uncertainties here. I beg to differ with some of your conclusions.

Senator WARNER. Thank you very much, Dr. Hibbard.

We will now hear from Mr. Donald Bauer, Principal Deputy Assistant Secretary for Fossil Energy.

STATEMENT OF DONALD L. BAUER, PRINCIPAL DEPUTY ASSISTANT SECRETARY FOR FOSSIL ENERGY, DEPARTMENT OF ENERGY

Mr. BAUER. Thank you, Mr. Chairman. In the interest of time I will ask permission to submit my formal statement for the record and briefly summarize my statement.

As the committee requested, I've concentrated my testimony on the technology of coal and I've prefaced my remarks with a quote from Winston Churchill who once said that the farther backward he looked, the farther forward he could see. I don't think we have to look back very far in this industry to see the significant strides we've made over the recent years. As I indicated in my statement, the tenth anniversary of the oil embargo, which began in October 1973, marks an appropriate date from which we can measure the progress that's been made in the coal industry and particularly in coal science and engineering. In the last decade, substantial advances have been made in our understanding of coal and our ability to use it efficiently and effectively and I hope before I conclude this morning that I leave the committee with the impression that we continue on to meet the technical challenges that face us today so that we can make better use of coal.

I think a common thread running through the emerging technology is the greater efficiency in the way we use coal and perhaps more important in American minds today, and as we just discussed in the last few moments, is a greater compatibility between coal and the environment. In my statement, I've tried to concentrate on the entire coal fuel chain—from the coal mine and cleaning plant, to the combustion process and through the gas cleanup step. At each of these points, coal of its combustible products, can be cleaned. The industry today has the technology to clean coal before it is shipped and burned. Coal washing can increase the reliability of today's coal-fired boilers and furnaces by removing some of the ash. It can reduce the sulfur levels and the coal, perhaps, by 30 to 50 percent. But that, by itself today, won't enable all the coals to meet the Clean Air Act standards. The utility industry today is sponsoring a program—and I would say an aggressive program—at the Electric Power Research Institute Homer City facility, which started operations in 1981. That facility provides a mechanism for utilities to subject their coals to a variety of conditions and test variables. A utility can determine the most effective combination which will result in that utility being able to minimize the generation cost of the power by increasing plant availability.

Now, our program at the Department of Energy is attempting to take that technology several steps forward. Our coal cleaning program has a distinctive environmental component to it. We want to develop an economical sequence of coal cleaning steps that will go after the sulfur and ash that today's technologies do not. We believe it may be possible to reduce the sulfur and ash content in coal before it is burned by 90 percent or more. Technically, on small scales, we've shown that to be feasible. That level of coal cleaning—I don't want to lead you astray—comes at a cost and the cost today would erode much of coal's economic advantage, if not all. However, our research program is concentrating on improved technology in an attempt to bring costs down. The types of research being sponsored in this area range from coal grinding—grinding down the coal to the size of talcum powder, just one-thousandth of an inch—to improved physical cleaning that will remove more of the pyritic sulfur in coal—to chemical techniques that will release the organic sulfur. Taken together, these technologies may give coal the environmental quality it needs so that it may replace oil and natural gas in either new or retrofit applications. Moving to the post-combustion stage, I'm talking about flue gas cleanup devices or, as they are commonly called today, scrubbers. Ten years ago scrubbers were a relative newcomer to the coal scene. And the early problems of integrating a complex chemical plant into an already complex power plant cause some utilities to balk. But today the utility industry has made considerable advances in the technology of flue gas scrubbing. Nearly 220 scrubbers are either in place, under construction, or planned for the utility coal-fired boilers today. Today's scrubbers will permit coal plants to achieve the air quality standards of the Clean Air Act. They are expensive, however, and for at least 85 percent of them the residual material they produce—a waste sludge—causes some environmental concern of its own. I have heard it labeled as a nuisance factor. Recently, however, the new scrubbing technique has been brought into commercial practice. The spray dryer system employs a chemistry that removes sulfur from coal in a dry form. The technique is used today almost solely on western coals although a commercial unit has been installed at the Department of Energy's Argonne National Laboratory that is using high-sulfur coal. We've done some tests at our Pittsburgh Energy Technology Center that show that there may be technical and economic potential for applying that technique to the high sulfur eastern coals. As in the coal cleaning program, our research efforts today are designed to push the technologies significantly beyond today's capabilities.

Our focus within the last 2 years, and we have refocused our scrubber program, has been to shift to the new generation scrubbers, one's that simultaneously remove sulfur dioxide, nitrogen oxides and, in some cases, particulates. The levels of sulfur reduction would be comparable to the scrubbers of today, but by developing steps in which both the sulfur and the nitrogen react together in a similar chemical fashion we believe that we can develop a concept that will remove 90 to 95 percent of the nitrogen oxides, as well. Like the spray dryer, the simultaneous SO_x/NO_x removal scrubbers that are being developed also would produce a dry, more easily disposed of residue.

Now I will outline some of the advances that have taken place inside the boiler. Fluidized bed combustion is a major achievement in the technology of burning coal. It is one that I believe the Government and private industry together can be proud of. Fluid bed combustion eliminates the need for scrubbers altogether. Sulfur capture, even from high sulphur coals, takes place inside the boiler and, by keeping the combustion temperatures low enough, one can minimize the formation of nitrogen oxides. Oh yes, capital costs are higher than for oil- or gas-fired boilers but the fuel costs are lower. And the fluidized bed boilers are significantly less expensive to build and operate than a conventional coal-fired boiler with a scrubber.

We, in the Government, believe we have an excellent example of a cooperative relationship where the private sector assumed the initiative from the Government when it saw there was a place in the marketplace for the fluidized bed. Today there are at least 60 atmospheric fluidized beds either operating, under construction, or on order. All of these are on an industrial scale. And we in Washington are proud of the fluidized bed initiatives, because we can see the culmination of our part in the research effort. We just need to look across from Capitol Hill to Georgetown University and we see that a Government-sponsored fluid bed boiler has operated there for 3 years successfully.

Senator **Warner**. If I might interrupt, since I'm quite familiar with that, when you say it operated successfully, could you elaborate as to how successful its been, as it has operated in the center of a congested population area.

Mr. **Bauer**. The atmospheric fluidized boiler at Georgetown Univesity was designed to generate steam to heat the university. It was designed, I believe, by Pope, Evans & Robbins, and the special bank of boiler tubes was designed by a contractor. When they set out with the design, they set a specific set of objectives to generate so much heat at a certain projected cost, compared with how they had been heating the university. They've met all those objectives for 3 years. Because of the size of the boiler, however, they are experiencing after 3 years, erosion of some of the tubes. They are going to have to be replaced. But if one did an economic analysis of heating that university with oil or gas as compared to what they're doing today, and one took the difference in those costs, as an investment, I bet you could replace those tubes every 4 or 5 years and break even. It's environmentally acceptable.

Senator WARNER. It's environmentally all right?

Mr. BAUER. You capture the sulfur inside the boiler and you can keep that temperature low enough that you do not form nitrogen oxide gas. It's successful.

On the utility side, the industry has also assumed the initiative in developing the utility version of the atmospheric fluidized bed power generation, and the 20-megawatt TVA unit at Paducah, KY, has operated successfully. TVA and EPRI are in discussions now about moving toward a 100 to 200-megawatt demonstration facility. We may hear some more on that later today. We've also focused our atmospheric fluidized bed program toward concepts which could have the potential to make fluidized bed combustion more competitive with oil or gas at a small industrial scale. And we have contracts out. Hopefully, we will select an advanced AFB concept soon for further evaluation and tests. We are also continuing to develop a pressurized fluidized bed concept in Grimethorpe, England, as well as the one stateside in New Jersey. Pressurized fluid beds will also be a power option for the power industry beginning in the late 1990's and beyond.

All of these options that I have talked about will permit the country to burn coal more cleanly and efficiently than we do today. But what I've said by no means exhausts the potential that coal offers for meeting our future energy needs. There are several other new technologies that we are pursuing in the Department of Energy or are being pursued by the private sector, I will name just a few which will enhance the use of coal. Coal/water, coal/water alcohol mixtures, the coal-fired turbine, retrofit coal combustor development, fuel cells and in the advanced processes, or work in coal gasification and liquefaction. In activities outside the Department, the Cool Water Gasification/Combined Cycle plant recently received a price guarantee from the U.S. Synthetic Fuels Corporation. That's another step forward for the coal and utilities sector. And finally, Mr. Chairman, I believe that we will continue to see longrange opportunities for synthetic fuels. Without a question, the pace of the commercial synfuels development has been slowed by the world energy and economic conditions, but if we look at what is being done in the Federal Government, the Synthetic Fuel Corporation is starting to select projects for award of incentives. In addition, some firms in the private sector, are going without Federal sponsorship, particularly the Tennessee Kodak project and the Allis Chalmers project. These projects, I believe, will establish a sound base of experience for the establishment of a commercial synfuel industry.

Mr. Chairman, let me summarize by saying that the expansion of coal's use in the future depends in large part on the pace of our economic growth. One has to forge an agenda of national priorities that will enable our tax dollars to be used wisely and avoid unnecessary and wasteful duplication. Research and development must compete with other pressing national concerns but we are convinced that Government can play an important role in expanding the technology base for the coal industry. A properly structured research program between the Federal Government, the industrial sector, and academia can provide the new ideas needed to ensure that the technology of coal continues to advance in the future.

Thank you, Mr. Chairman, and as you requested, I will be pleased to answer any questions.

[The prepared statement of Mr. Bauer follows:]

Statement of
Donald L. Bauer
Principal Deputy Assistant Secretary
for Fossil Energy, U.S. Department of Energy
to the
Subcommittee on Energy and Mineral Resources
Senate Committee on Energy & Natural Resources
August 9, 1983

Mr. Chairman, I am pleased to represent the Department of Energy at today's hearing. As you requested, I will focus my remarks this afternoon on the recent technological progress that has taken place in the use of coal in this country and the prospects for continued innovation.

As a preface to my remarks, Mr. Chairman, I would call the Committee's attention to a statement by Winston Churchill who once said that the farther backward he looked, the farther forward he could see. Likewise, as this nation approaches the 10-year anniversary of the Middle East oil embargo, those who have been involved in coal-related research might look at the future from the perspective of how far we've traveled in the recent past -- specifically in the past decade.

The national consciousness was heightened in the 1970s by the oil embargo, subsequent price hikes, and a concern about the quality of our environment. In response, a concerted effort picked up momentum in the nation's research laboratories, both public and private, to improve and broaden the technology base for coal, the nation's most abundant, secure and economic energy resource.

That effort is now beginning to return dividends.

To illustrate this, I would like to concentrate on three points in coal's conventional "fuel chain" where major technological advances have occurred and are continuing to take place -- in precombustion cleaning, at the stack, and in the combustor or boiler itself. I will then touch briefly on some of the concepts that could expand the future use of coal, for example as a slurry fuel for use in oil- and gas-fired combustors, or as a feedstock for gas turbines and stationary diesel engines, or for use in gasified form as a fuel for a combined cycle power plant or a fuel cell.

A common thread running through each of these emerging technologies is an improvement in the efficiency of coal use and in its compatibility with our national environmental goals.

Precombustion cleaning: For many years, when coal was mined by pick and shovel, quality was maintained simply by hand loading only the visibly clean coal. As the coal industry adopted more mechanized mining methods, which discriminate less precisely between coal and impurities, delivered coal quality began to decline. During the past 10 years, the increasing mineral content in mined coal has meant that the average quality of coal burned in power plants has fallen in terms of its energy producing potential from an average of 11,750 Btu/lb to 10,600 Btu/lb.

Although power plant boilers can be designed to burn almost any grade of coal, the firing of coal that is inferior to the design specifications often results in decreased plant availability. To counter this, the electric utility industry through its research arm, the Electric Power Research Institute (EPRI), began an aggressive program in the latter 1970s, to upgrade the quality of coal through the development of improved coal cleaning techniques.

Much of this research is being conducted at the $15 million Coal Cleaning Test Facility built by EPRI in 1981 near Homer City, Pennsylvania. Cosponsored by the Pennsylvania Electric Co., New York State Electric & Gas Corp., and the Empire State Electric Energy Research Corp., this facility has the capacity to simulate, at commercial scale, a large number of fine coal cleaning processes. The principal objective of this work is to assist electric utilities in determining which of several cleaning processes is the most effective in minimizing electrical generating costs through increased plant availability.

By upgrading the quality of coal to the level originally specified, while minimizing the loss of Btu value in the cleaning process, the industry hopes to achieve a significant increase in steam generator availability and reliability. In addition, the performance and reliability of subsequent environmental control technologies, such as flue-gas scrubbers, are improved by some degree of pre-combustion coal cleaning.

By comparison, the Energy Department's research program is attempting to develop a solid technological base for advancing the capability of coal cleaning technology significantly beyond that being pursued by the private sector. Our goal is to develop a process containing a sequence of advanced coal cleaning steps capable of reducing impurities low enough so that coal not only could be burned cleanly and more effectively but ultimately could replace oil or natural gas, either as a slurry or a conditioned product, in both new and retrofit applications.

In short, we believe it may be possible, if costs can be lowered to a reasonable range, to develop the technology that will permit the country to burn coal much like we already burn petroleum. In some applications, this could require the removal of perhaps as much as 90 percent of the sulfur and up to 95 percent of the ash in coal. Several recent laboratory and small-scale tests now give us confidence that these levels can be attained.

To achieve this quality, coal may require grinding to sizes much finer than are common today, in some cases to particles roughly 1/1000th of an inch in diameter (finer than the consistency of talcum powder). This releases greater amounts of mineral matter making sulfur and ash removal easier and more effective. The Federal fossil energy research program is studying various energy-efficient approaches to achieve this size reduction, including the use of high-frequency ultrasonic grinding devices.

Following grinding, removal of ash and sulfur can be accomplished in one of two ways, physical coal cleaning or chemical cleaning, or perhaps a combination of the two. Conventional physical coal cleaning, which relies on properties such as density, surface characteristics, and magnetic susceptibilities, can reduce sulfur and ash levels by 33-50 percent. The sulfur removed is essentially "pyritic" sulfur (meaning that it is combined with iron and occurs within coal as finely dispersed, physically distinct particles). The Department's research program is funding the development of improved physical techniques that could improve the reduction level to 60-65 percent.

To achieve the 90 percent sulfur reduction levels, organic sulfur -- sulfur chemically bound to the coal -- must also be removed. Chemical cleaning methods being developed with DOE funding either displace sulfur with basic alkali metals, such as sodium, calcium, or potassium, or they oxidize the sulfur. In either case, the sulfur is converted into a water-soluble form which can be removed by washing.

The Department is also funding research on a longer-range approach that would employ microbiological techniques as promising new ways to desulfurize coal.

Improved coal cleaning will become increasingly important as coal operators strive to meet the increasing demands of the marketplace. This will be true whether one considers the utility market, the steel manufacturing industry, the export market, or the industrial and retail markets. From an environmental standpoint, combinations of physical and chemical cleaning steps, which could be ready for commercial application in the early 1990s, may have the potential for reducing sulfur dioxide emissions between 80 and 94 percent.

At the stack: During the past decade, a significant evolution in flue gas desulfurization systems -- so-called "scrubbers" -- has taken place within the power industry. In the mid to late 1960s, with initial promulgation of local sulfur dioxide standards, electric utilities used flue gas scrubbing principally as a last resort. During these early years, other less costly options for mitigating the effects of sulfur emissions existed, such as use of low sulfur coal, dispersal by tall stacks, intermittent control by load or fuel switching, and coal-cleaning. These alternatives, for the most part, were operations utilities understood and with which they were familiar.

But as national sulfur dioxide control legislation and regulations evolved through the 1970s with the Clean Air Act Amendments of 1970 and 1977 and with the New Source Performance Standards of 1971 and their revisions in 1979, continuous sulfur dioxide removal became a requirement rather than an option.

Lack of expertise and experience in the process chemistry required for flue gas desulfurization, frequently on the part of both the utility and the vendor, delayed the orderly implementation of the technology. Problems associated with plugging of gas passages, corrosion, and construction materials plagued the early scrubber systems and often kept maintenance and operating costs high.

Today, however, roughly 10 years after the industry began developing the data and understanding required to solve these problems, nearly 220 flue gas scrubbers are in place, under construction, or planned on utility coal-fired boilers, representing approximately 100 gigawatts of capacity. Utilities, backed in part by Federal support, have developed techniques to make scrubbers work more efficiently and reliably. System hardware has been simplified and more corrosion-resistant alloys have been applied.

Although still expensive -- a scrubber can represent as much as 20 percent of a power plant's cost -- these systems permit coal to be burned cleanly at costs still less than burning oil.

Of the variety of flue gas clean-up systems available today, more than 85 percent are the "wet" lime/limestone systems. A principal drawback of the wet scrubber, however, is its residue. When it leaves the power plant, the residue is a wet sludge that never dries. It is difficult to concentrate and must be stored in large settling ponds lined by clay or plastic to prevent seepage. During its lifetime, a typical 500-megawatt power plant with a wet scrubber is likely to require a sludge disposal pond of more than 400 acres and perhaps up to 40 feet deep. As much as 20 percent of the capital and 5-10 percent of the operating costs of a scrubber system typically are for sludge disposal.

Industry has today taken the lead in developing a promising and fast-growing alternative to wet scrubbing -- the spray-dryer system. Although a fine wet mist of dissolved or partly dissolved alkaline chemicals is still used to capture sulfur dioxide, the amount of moisture is controlled so that the hot flue gas is only partially saturated and the reaction products remain dry. The solid waste products can be caught and disposed of in an environmentally acceptable form.

The primary advantages of spray drying over wet scrubbing are reduced pumping requirements (1000 times less water is pumped), reduced water consumption, elimination of reheating, reduced concern about corrosion, and the ease of handling a dry product.

Spray drying has gone from pilot to commercial application in the last six years. At least 14 spray drying units have now been sold to industries and utilities in sizes up to 600 megawatts. All have been for facilities using western low-sulfur coal. A major part of DOE's program in 1980 and 1981 was to determine whether similar systems could be developed for the higher-sulfur eastern coals. In 1981, Federal researchers found that by carefully controlling the temperature and humidity inside the dryer, more than 90 percent of sulfur from eastern coal could be captured using only half the amount of limestone previously thought required.

In 1982, the first dry scrubber in the world designed for high-sulfur coal combustion was put into operation at the main steam boiler plant at the Department of Energy's Argonne National Laboratory outside of Chicago. The cost of using Illinois-basin coal with the new scrubber has been compared favorably with the cost of low-sulfur coal from the western U.S. and is about $1 million a year cheaper than an equivalent amount of oil or natural gas.

The technical and economic advantages revealed by the laboratory tests and the experience at Argonne National Laboratory are expected to add to industry's momentum in moving this new technology into the eastern coal market.

With these technical advances now taking place within the industry, the Department's flue gas cleanup program refocused its efforts in 1982 to develop a new, more advanced generation of environmental control systems. Specifically, research is now concentrating on the simultaneous removal of sulfur dioxide, nitrogen oxides and, in some cases, particulates (i.e., respirable particles) from the flue gas of coal combustion.

One approach would beam electrons through the combustion gases that have been treated with either ammonia or an aqueous mixture of lime. The electrons cause a complex series of chemical reactions to take place in which the sulfur and nitrogen oxides are converted to dry materials that can be removed by conventional techniques. Another concept would use copper oxide to remove sulfur dioxide at temperatures also suitable for simultaneous nitrogen oxide removal with ammonia.

While these advanced concepts are expected to be capable of reducing sulfur dioxide emissions by 90 to 95 percent, comparable to conventional lime/limestone scrubbers, they also could reduce nitrogen oxides by a similar 90 to 95 percent (conventional scrubbers typically capture only 10 to 20 percent of the nitrogen oxides). Like the spray dryer, the simultaneous sulfur dioxide/nitrogen oxide removal systems also produce dry products, some of which may have commercial value.

In the combustor or boiler: Coal-fired combustors have relied on essentially the same principles since the 1920s when pulverized coal was first used to generate steam. Industry has improved this technology so that today's boilers are much larger, produce steam at much higher temperatures and pressures than half a century ago, and are more efficient in converting the energy in coal into steam. But the concept of grinding the coal to very small size and blowing it with air into large furnace cavities, where the cloud of coal dust burns much like a fuel gas, is still the way most coal is burned today.

Within the past decade, however, a new concept in coal combustion has moved off the drawing boards and into the industrial market. Developed through a joint government/industry program, fluidized bed combustion today has become the first major advancement in modern-day coal combustion.

The major advantage of the fluidized bed combustion concept is that sulfur removal occurs inside the combustor, eliminating the need for a scrubber. Also, combustion temperatures are substantially lower than a conventional coal burner, thereby reducing the formation of nitrogen oxides to about half today's air quality standards.

While the capital costs of fluidized bed boilers are significantly higher than conventional oil- or gas-fired boilers (5-8 times), the systems compare favorably to oil and gas firing at the larger scales (generation of 150,000 pounds of steam or greater) and are significantly more economical to operate than a conventional coal-fired boiler with a scrubber.

Today, the atmospheric pressure version of the fluidized bed concept is commercially available for industrial applications. Nearly every major boiler manufacturer either offers a fluidized bed combustor in its product line or is developing a commercial system for marketing. Approximately 60 atmospheric fluidized bed systems are either operating, under construction, or on order (the most recently reported sale took place last month to an Illinois chemical company that will use a coal-fired system for process steam and to cogenerate electricity).

The electric power industry has also assumed the initiative in developing a utility atmospheric fluidized bed power plant. Development of a utility-scale system has taken place at the Tennessee Valley Authority's $68 million, 20-megawatt (200,000 pounds of steam) pilot plant near Paducah, KY, and next month, the Electric Power Research Institute's board of directors will consider recommendations on the design and construction of a 100-200 megawatt demonstration power plant. If testing of the atmospheric fluidized bed process at this size proves successful in the late 1980s, the nation's electric utilities would have the option of building a new generation of power plants in the 1990s that could burn coal more efficiently while producing fewer emissions than existing coal-fired plants.

The Energy Department's program is currently concentrating on more innovative fluidized bed concepts having the potential to make coal competitive in smaller industrial boilers where oil or gas is now more economical, and on the pressurized version which may have potential application in future combined cycle power plants. In 1983, the Department is collecting data from the 80-megawatt (thermal) pressurized fluidized bed (PFB) boiler in Grimethorpe, England, which is co-funded by the United Kingdom and the Federal Republic of Germany. Funding is also being provided to complete construction of the 13-megawatt (electric) fully integrated PFB pilot plant at Wood-Ridge, NJ, which will be operated by the Curtiss-Wright Corp.

Research is also being supported to determine the survivability of gas turbine materials in a PFB environment and to gauge the concept's performance on alternate fuels, including lignite and low-rank coals and coal-water slurries.

Future Coal Applications

We are confident that the efforts of the private sector, motivated by the benefits of coal's low and stable costs, coupled with the research and development supported by the Department of Energy, will provide the coal industry a wide range of progressive innovations that will ensure that this abundant fuel continues to be a logical choice to meet future energy demands.

The options I've described, however, do not exhaust the full potential of coal's role in the nation's energy future. The technologies I've described will permit coal to be burned more efficiently and with improved environmental performance in applications where coal is used today. In the future, an array of new concepts may permit coal to move into new markets or applications, some of which currently rely predominantly on oil or gas. For example:

Coal-Water Mixtures: The advent of coal-water and coal-water-alcohol mixtures could be of major importance to the coal industry. Finely-ground coal suspended in water using additives to enhance handling and to minimize settling produces a fuel that can be handled like a liquid. This would eliminate the need for coal yards and on-site coal preparation and handling equipment. The liquid fuel infrastructure would be preserved. Coupled with advanced coal cleaning technologies to remove ash and sulfur, coal-liquid fuels could attain the same environmental and boiler operability performance levels as petroleum. Coal-liquid mixtures may find future applications in existing oil/gas designed facilities as well as in new capacity for utility, industrial, and residential/commercial boilers, furnaces, and process heaters.

Coal-Fired Turbines: The results of research in the last few years has encouraged the use of coal in gas turbines, an idea once pursued and discarded in the 1950s. If technical concerns regarding erosion, corrosion, deposition, and potential environmental constraints can be overcome through technological advances, the inherent advantages of gas turbines -- short lead times, factory-built modules, and low capital costs -- could become available for the coal industry. Research is now concentrating on the use of coal slurries or gasified coal as the turbine fuel. Advanced coal cleaning technologies and improved cooling techniques for turbine components could also play a significant role in the ultimate success of this concept.

Retrofit Coal Combustors: The Energy Department is preparing to fund several concepts for coal-fired combustors that could be installed on existing oil and gas-designed boilers and furnaces. The concepts are intended to remove ash and other potential pollutants directly from the combustors before they enter the boiler. Many of the concepts, which were selected by the Department in February, would remove the ash while it is still in a molten form called "slag", thereby accounting for the name "slag-rejecting" combustors.

Fuel Cells: Because they generate electricity and heat through a clean, electrochemical reaction rather than by combustion, fuel cells are expected to become attractive options for supplying future energy needs, particularly in environmentally constrained regions. Working with the gas and electric utility industry, the Energy Department's emphasis is to develop fuel cell systems capable of operating on natural gas and coal-derived fuels with long enough lifetimes and sufficiently low costs to be practical and reliable. On-site 40-kilowatt systems are now being installed and tested in commercial environments, and the first utility prototype unit in the U.S. is expected to begin operating in late summer in New York City.

Magnetohydrodynamics: The U.S. government's program has concentrated on developing individual components of the MHD system, a concept in which coal is burned at extremely high temperatures and the gases channeled through an intense magnetic field to generate electricity. Research has progressed to the first "power train" tests of the MHD system at the 50 megawatt (thermal) Component Development and Integration Facility in Butte, MT., and the 28-megawatt (thermal) Coal Fired Flow Facility in Tullahoma, TN.

MHD, however, has higher development costs than other coal-fired options, and a number of technical problems well beyond the current state-of-the-art still require significant technical advances. It may be more appropriate, therefore, to focus research on the fundamental scientific aspects of MHD, rather than pursue rapid large-scale engineering demonstration with its attendant high costs and risks.

Gasification/Combined Cycle: In 1984, completion of the 100-megawatt Cool Water gasification/combined cycle power plant will mark a major milestone in the use of coal to generate electricity. Located at Daggett, CA, the commercial-scale demonstration project will integrate the gasification of coal with the generation of electricity by a combination of gas and steam turbines. Integration means that the coal gasification and electricity generation processes are simultaneous and synchronized; there is no buffer of stored fuel between them. Even more important, the processes actually interact, notably by their exchange of heat. These features are key to the efficiency and economy of integrated gasification/combined cycle power plants.

The California site illustrates another important feature of this new path from coal to electricity. Exhaust emissions of particulate matter, sulfur dioxide, and nitrogen oxides are expected to be well below Federal requirements for new power plants, thus meeting the still tighter limits required by California law.

The Cool Water project is being sponsored by Texaco, Southern California Edison Company, the Electric Power Research Institute, the General Electric Company, the Bechtel Power Corporation, the Empire State Electric Energy Research Corp., and JCWP, a Japanese consortium. Last month, the Board of Directors of the U.S. Synthetic Fuels Corporation initiated its first award of financial assistance by announcing its intention to award $120 million in price guarantees to this pioneering venture.

Within the Department, activities are underway to improve the gasification/combined cycle concept by developing more effective means to clean impurities from the hot gases exiting the coal gasifier. Another DOE research project is attempting to determine if cooling gas turbine components to very low levels will permit coal gas to be used with only minimal cleaning (see Coal-Fired Turbines, p. 10).

Synthetic Fuels: While the pace for substantial commercial synthetic fuels production in the 1980s and 1990s has slowed due to lower energy prices and falling demand, the Department continues to forecast a need for oil and gas derived from coal, shale and other resources beginning around the turn of the century.

To ensure that a sound base of commercial experience is in place when market forces dictate an expansion of synfuels technology, the Department has provided loan guarantee assistance to the Great Plains coal gasification plant in North Dakota. (Assistance was provided under the DOE Alternative Fuels Program, a precursor to the activities of the U.S. Synthetic Fuels Corporation.) Construction of the $2.1 billion project is currently approaching the 60 percent completion stage, with procurement and engineering now 100 percent complete. Start-up of the first gas production train will begin in about a year with the plant scheduled to be in full production by the end of December 1984. As required under the loan guarantee agreement, the Department is continuing to analyze estimates of the anticipated cash-flow of the project once it begins operations, particularly in light of current lower-than-expected oil and gas price projections. To date, however, we have not received a request to modify the financial agreement with the 5-member Great Plains partnership, and we are continuing to approve disbursements from the Department of Treasury's Federal Financing Bank under terms of the current loan guarantee.

The Department is also continuing to support a broad research program to strengthen the current knowledge base for both coal gasification and liquefaction. Within the last 10 years, the federal R&D program has funded the development of several modern day advanced coal liquefaction technologies, including the Exxon Donor Solvent and H-Coal processes. Both represent substantial improvements over the older generation German technologies and will provide a solid technical foundation for converting coal to liquid fuels when market forces dictate.

Our activities are now concentrated on basic and applied research leading through the proof-of-concept stage for several even more advanced synfuel technologies. From this program, we hope to develop the basic knowledge for new synfuel concepts, such as the two-stage approach to coal liquefaction, that could offer significant improvements in efficiency and economics over today's state-of-the-art. And with several advanced coal gasifiers now ready for marketing, our gasification program has been restructured to encompass potential improvements in the overall coal-to-gas system including the cleanup and treatment of waste products.

We are continuing to support work with the private sector to develop the technology for the underground, or "in situ", conversion of coal into synthetic gas which could then be upgraded or converted to liquid fuels or chemicals on the surface. Underground coal gasification may be a future key to tapping the energy content of coal seams that are unmineable with today's technology. Our technology efforts are currently focusing on a promising new concept developed by the Lawrence Livermore Laboratory that employs a series of controlled gasification "burns" moving from the bottom to the top of the coal seam rather than horizontally as in past tests.

Finally, we are continuing to cooperate with the U.S. Synthetic Fuels Corporation and its private sector partners in such areas as environmental monitoring consultation, as the Corporation begins to make its first financial incentive awards for commercial-scale synfuel projects.

Conclusion

Mr. Chairman, let me summarize by saying that the expansion of coal's use in the future will depend in large measure on the pace of economic growth. But it will also hinge on our ability -- both in government and in the private sector -- to develop technologies that are efficient, economical, and environmentally clean.

We believe our role in government is to work with industry in establishing a sound scientific, technical and regulatory environment from which new concepts can emerge and, if they offer sufficient market potential, be scaled-up and commercialized promptly and efficiently by the private sector.

The foremost challenge facing this country, Mr. Chairman, is to forge an agenda of national priorities that will enable tax dollars to be invested wisely and without unnecessary and wasteful duplication. Research and development must compete with other pressing national concerns for a limited number of public dollars. However, we are convinced that Government can play an important role in expanding the technological base of the coal industry. Through a properly structured research program involving Federal, industrial, and academic institutions, we can provide the new ideas needed to ensure that the technology of coal continues to advance in the future.

Thank you.

Senator **Warner**. Thank you for your time and if you would be kind enough to inform the committee with those present of the work being done by your Department.

Mr. **Bauer**. As Mr. Princiotta has said, the President asked the Administrator of EPA to reexamine the acid rain issue and submit, sometime in September, a report on acid rain. The Department of Energy is a member of the interagency task force on acid rain. Also, we are participating in the preparation of discussion papers with the EPA staff. The papers being generated talk about the state of the science, the examination of the options, the anticipated environmental results, and finally, how one implements and manages the final decisions that are made. I might say, with your permission, Mr. Chairman, that the Department has worked closely with EPA on technology programs—Frank has talked about some. We jointly coordinate our programs in controlled technology, for example, in DOE and EPA co-funded projects. Where DOE has a long-term objective and EPA has a near term need, we put that money together to solve a common problem. And that's what I mean by avoiding duplication of efforts. So there is close coordination. I have probably a dozen people who are participating.

Senator **Warner**. I don't question the close coordination, the funding, an so forth, but where are we, in your judgment, on this issue?

Mr. **Bauer**. The issue of acid rain has as many unanswered questions as there are experts in the field. I believe today that the acid rain issue is boiling down to the collection of the scientific data—this is what we're doing in the Department—and applying that against the options. The options include lake liming, for example. I saw some data the other day which said if you lime 1,000 lakes of 100 acres each 3 times a year that costs $10 million. In attempting to impove our basic understanding of the data we have today and analyzing the options and seeing what actions we can take, we are supportive of EPA. They have the lead assignment and, along with our technology work, we are there to support them, Mr. Chairman.

Senator **Warner**. Our first panel today on "Technology Undertaken by Private Enterprise for Developing New Coal Markets" is composed of Dr. Arthur M. Squires, university distinguished professor, Department of Chemical Engineering, VPI; Mr. Richard Wolfe, vice president, United Coal Co.; and Mr. Charles Henderson, senior vice president for research and development, Atlantic Research Corp. We will lead off with Dr. Squires. You are a familiar spokesman in this area and we look forward to hearing from you today.

STATEMENT OF DR. ARTHUR M. SQUIRES, UNIVERSITY DISTINGUISHED PROFESSOR, DEPARTMENT OF CHEMICAL ENGINEERING, VIRGINIA TECH

Dr. **Squires**. Its a pleasure to be here. In my testimony, which I have submitted for the record, on page 3 and 4 I tried to summarize coal markets present day and potential. In the testimony, I've discussed most of them. But in my time for this verbal testimony, I'd like to focus on just a few—starting off with railroad locomotives, which is on page 4 of my testimony. There is a potential here for something like 40 million tons of new coal a year produced to be burned in locomotives, as the number in the center column there indicates. And I'm very glad to be able to report that Ross Rowland, whom you met in Washington in September of 80 has put a consortium together. A limited partnership consisting of Burlington Northern Railway, Chessie Systems, Babcock & Wilcox/McDermott, and his own company, American Coal Enterprises and will be beginning engineering work quite seriously on a roughly $30 to $50 million privately funded exercise to build a coal fired steam locomotive that should be on the rails about eighteen months to two year after the beginning of the effort. It will produce a return of more than 50 percent on the capital that the railroads expect to put into it. It is very profitable to replace diesel fuel with coal. As a person interested in the combustion of coal, I am fascinated by the technique they plan to use. An invention of the brilliant Argentine, Livio Dante Porta. This has been practical in Argentina for nearly 30 years. Our technical societies do not do a very good job of telling us how the new advances, particularly in coal combustion in other countries are progressing. And if we're talking about advanced technology theme, my written testimony is that there's a lot of other technology around the world such as Porta's exciting new technique for burning coal that we should pay more attention to. The government and particularly our land grant university should have a role, in this regard. Another item in my list of coalmarkets is export of coal overseas. This is a market that's threatened, as has already been mentioned by other witnesses this morning. I visited the Mitzibuchi Works at Wakayama, Japan, in January of 1981 and found them using 10-percent Pocahontas seam coal in their coke oven charge with a 3-percent mixture of subbituminous Australian coal that no coke maker in 1970 would have dreamed could possibly go into a coke-oven charge. The trick to making this substance work is that along with the 3 percent of Australian coal there is 1 percent of a pitch, a special pitch coming from the petroleum industry called Eureka pitch. In scientific terms what this pitch is doing is converting the Australian coal into a coking coal or a suitable admixture for a coke oven charge. They would be using much more of this Australian coal than 3 percent except for the fact that there would be about 5- to 6-percent sulfur. That puts a limit on the subbituminous coal they can use. They were very candid with me that their research is on a thrust to find other pitches, produced from coal, that are low in sulfur but have the special properties of Eureka pitch so that they can increase the 3 percent, they hope, to something like 10 or 15 percent and, quite frankly, with the objective of eliminating Pocahontas coal, Virginia coal, from their coke oven charges. We badly need in the United States intensive research on coke making, scientific work to really understand what the Japanese are doing. Very few people in the United States understand this, especially very few university scientists. There need to be scientists in our universities looking at the fundamentals of coke making and looking at what qualities Pocahontas seam coal has that Eureka pitch might not have or some other future pitch might not have so that we can convince our customers that they should continue to use our coal.

The rest of my time, I'd like to focus upon markets for space heat and hot water. In the second part of my testimony is an essay on the costs, the environmental problems, and something about programs, the techniques for marketing coal and making it acceptable in the consumer's eye for space heat and hot water. And if you will look on my page 3, you will see that we are talking about something in the neighborhood of 55 million tons output by oil and 550 tons of coal could be used per year to replace oil now being used in residences for space heat and hot water and on the order of 40 in commercial establishments and industry. Approximately 100 million tons of coal could be sold for space heat and hot water by simply replacing oil which we now use. Now, I have to summarize, but let me say that the economics of doing this are extremely attractive. The payback to somebody who buys a coal furnace for the home which is now buring oil or using electricity, the payback for that coal furnace proposed in the differential for the fuel is rapid. From a national point of view, the investment in that coal furnace in that home is a far cheaper thing then a synthetic oil plan, or a synthetic natural gas plan, or a new electricity supplier. I am talking about a factor of maybe 4- or 5-times cheaper for the country, for little consumers, and small businessmen who manufacture stoves and distribute them and sell them. It is far cheaper, far more economical for the country to move to the correct combustion of coal for space heat and hot water in homes and incommercial establishments then going for the high-tech option, synthetic fuels for electricity. Now I've said using coal for space heat and hot water. I think realistically if we're talking domestic space heat and hot water we should be talking smokeless fuels. We used to have smokeless fuels in this country. The anthracite industry once mined as much as 80 to 100 million tons a year, in their peak year. Last year, they probably mined 2 million or maybe recovered 3 million more from waste products. The anthracite industry is practically moribund and its very hard to see how it could be designed but about 2 months ago I made a very exciting trip to Van Sant, VA, where Jewel Smokeless Coal Co. has a new coke oven. Its, in essence, an update of the old beehive oven but without the environmental problems. It was very clean. The local people in Van Sant don't think they'll operate, they think they'll shut down because of the status of heat. A very clean new coke oven, very cheap, and they're doing very well on the coke market selling most of their product production on a large scale in Detroit.

Senator **Warner**. Is the coke they are producing cost competitive?

Dr. **Squires**. Yes, at less than $100 a ton for the coke product. That's some of their product that I put there on your desk—that is metallurgical coal produced in Van Sant, VA, from Virginia coal. By the way, I am not sure I am disagreeing with an earlier witness but I think there is going to be a major boom in coke sales on the world market because the steel companies have been shutting down their coke ovens all over the world. Where are they going to get coke when they start making steel? Jewel Smokeless has, I think, a very fine technology for expanding their production quickly. A pilot project could be set up—I'll make a specific proposal now—to provide coke from Van Sant to homeowners in Roanoke, say, who are now buying kerosene heaters. Why are they buying these heaters? Because they want to shut down their central furnace, save on their central furnace heating bill, and only keep a small part of their house warm. People would go for this. It would seem like an answer to a prayer. There are 15 million homes in the United States burning at least a half a cord a year of wood. And I've been in some of these homes around Blacksburg where colleagues of mine who, I am sure, are earning $40,000, $50,000, or $60,000 a year and they are burning wood. Come on! The American people will burn solid fuel if its made available to them. And a coal fire, particularly a coal-burning anthracite fire is the lazy man's alternative to a wood fire. This is easy. I visited a friend of mine, a retired employee of the British Steel Corp., a blast furnace expert. I was in his home on three different occasions for a total of probably 15 days before I realized he heated his house with coal. I hadn't caught him in the morning at his 2-minute chore of topping up the coal bunker and taking out the ashes. And there's equipment on the market in England today where you only have to do that once a week. Not a big deal and clean. Not the old smoke that people are used to. We need to bring some of these English stoves, and develop the fuels likewise, bring them to Roanoke and show them to the people. We must bring in a supply of coke to enough people so that the word gets out. This would be, I am convinced, a paying proposition. It needs a shove. Here again, the land-grant university would provide it. The extension divisions are used to doing this kind of exercise. Another exercise would be to find 20 or 30 chicken farmers and provide them with roughly 1 to 2 million Btu and the stove that they would need and line up supplies of quality coal, quality sufficient for that device. Now we've heard a lot about quality this morning—and I am stressing that coal has to be tailored to the device. The customer is going to flee from the product if he can't get a reliable supply of the coal that his device needs. So I'm talking now about a fairly complex exercise—we might even run 20 chicken houses from propane heat to coal heat, but its worth doing to make coal visible. It would involve again, perhaps an extension division exercise lining up the coal supplies, probably using one of the Southern State's farm cooperatives to distribute the coal and help the chicken farmers. The chicken farmers, a few of them ought to go to Norway and see some of stokers that have been installed there just within the last 18 months to provide heat for greenhouses. Farmers are delighted with it.

Senator WARNER. Dr. Squires, I suggest that primarily your contribution is to inform us that thechnology has proceeded to the point where we can go back and reinstitute some of the markets that we had a generation ago in this country?

Dr. SQUIRES. Yes; and I believe, Senator Warner, that I'm talking about a lot of coal mined by the coal miners of southwestern Virginia because we have low-sulfur coal, we have the ideal coal to convert to smokeless fuels or to go to those chicken houses and would not put a big burden of sulfur oxides into the atmosphere.

[The prepared statement of Dr. Squires follows:]

Testimony for Field Hearing of the
United States Senate Subcommittee on Energy and Mineral Resources

Enhanced Coal Technology — Coal's Markets for the 1980s

Donaldson-Brown Center for Continuing Education,
Virginia Polytechnic Institute & State University

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MARKETS FOR U.S. COAL — OPPORTUNITIES, AND A DANGER

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In Part I, I will review present and potential markets for coal mined in the United States, describing

- the status of technological understanding both here and abroad;

  It is not always true that the most advanced technology is well known here. For several markets, there is technology overseas which we need both to learn and to make more visible here — or, at the very least, to learn more about if we wish to compete in selling coal to these markets worldwide.

- roles that government should play in transfer of technology —

  — transfer to potential customers for U.S. coal, both here and abroad — especially unsophisticated customers whose furnaces are small,

  — transfer of technology *to* the United States *from* abroad;

- early opportunities for expansion of certain domestic and export markets;

- governmental actions that could help the private sector realize these opportunities more quickly;

- a threat to our overseas market for metallurgical coal that needs to be countered with defensive research.

In Part II, I will say something in greater detail about problems, both real and merely psychological, which we face in developing markets for coal in small furnaces supplying space heat and hot water — for homes, agriculture, business, and industry.

Our nation's energy planning has neglected this opportunity. Requests for Proposals and Notices of Program Interest (RFPs and NPIs) from the Department of Energy, for example, have often set 20 million Btu per hour as the lower limit of interest at the Department for innovative research or applications in coal combustion. Yet there is a large economic incentive, from viewpoint of both national and individual interests, to replace oil or electricity now used for space heat with coal. If recent trends in gas prices persist, the incentive to replace gas with coal will also soon be great.

An implied theme of my testimony is how little energy planners have taken into account the interests of several important groups among Virginia's citizens:

- The southwestern Virginia coal miner. Japanese scientists are well along in a program of research aimed at elminating his metallurgical coals from Japanese coke manufacture. The southwestern Virginia coal miner needs help to defend this market. He needs new sales opportunities:

  — manufacture of coke for export;

  — conversion of his low-sulfur bituminous coals into smokeless solid fuels for domestic use;

  — development of "smoke eaters" that can burn his bituminous coals, in their raw state, smokelessly — i.e., domestic stoves of advanced design like those available to householders in Great Britain and New Zealand;

  — activities to promote commercial use of his low-sulfur coals at a scale of heat need too small for economic employment of either flue-gas scrubbers or combustion in a fluidized bed of limestone — e.g., to promote use of low-sulfur coals on Virginia's farms, which often need heat at the 1 to 3 million Btu per hour scale.

- The householder who is today buying a kerosine heater to provide supplemental heat in just one room, to save on his bill for central heating. He needs to be able to buy smokeless solid fuels.

- The chicken farmer who uses propane for space heat in his growout houses. Along with hog farmers and tobacco growers, he needs to be shown the coal option.

Part I. *SURVEY OF MARKETS FOR UNITED STATES COAL*

Table 1 surveys present and potential markets for coal mined in the United States. I have organized the data in categories different from those in which energy data are usually compiled. I have attempted to display the data in categories reflecting more closely a set of technological approaches to the use of coal. This means that I have had to divide some of the standard categories into several sub-categories; and often, I have been forced to do some guessing at the divisions.

Most figures in Table 1 are for 1981; some markets have shrunk badly since that year. I would emphasize that some figures are guesses.

I will say something in this Part I about those markets which I believe represent coal's best opportunities for early growth — or, in one instance, an important market that is threatened.

Table 1

Present and Potential Markets for Coal Mined in the United States

	Present Fuel Consumed by Market, expressed in millions of tons of coal equivalent per year — (some values are approximate)—		
Market	*Coal*	*Oil*	*Gas*
Generation of electricity	570	80	140
Residential space heat and hot water	6.4	55	180
Commercial and industrial space heat and hot water	small	40	100
Heat for oil and gas production	nil[1]	small?	60
Process heat in petroleum refineries	nil	35	30
Process heat in chemical industry	nil	20	30

[1] Several demonstrations of use of coal to raise steam for secondary oil recovery are underway, each using fluidized-bed combustion.

Market	*Coal*	*Oil*	*Gas*
Process heat in steel industry	4[2]	small	75
Process heat in other industry	50	50	105
Chemical feedstocks	nil[3]	50	25
Railroad locomotives	nil	40[4]	nil
Barges, tugs, and ships	small	?	nil
Metallurgical coal to manufacture coke for domestic steelmaking	60		
Exports of steam coal for heat	45		
Exports of metallurgical coal for manufacture of coke overseas	65		
Metallurgical coal to manufacture coke for export	nil		
Bituminous coal to manufacture smokeless solid fuels for domestic market and export	nil		
Anthracite coal for domestic market and export	5		
Manufacture of synthetic fuels	nil		

[2] Does not include coke-oven and blast-furnace gases, which are, in essence, byproducts from manufacture and use of coke in steelmaking.

[3] Does not include coke-oven byproducts. Tennessee Eastman's new acetic anhydride plant will soon use coal as feedstock.

[4] Here, the "coal equivalent" takes into account the higher efficiency of the diesel engine in comparison with the coal-fired steam locomotive to be built by Coal-Oriented Advanced Locomotive Systems ("COALS").

Generation of Electricity

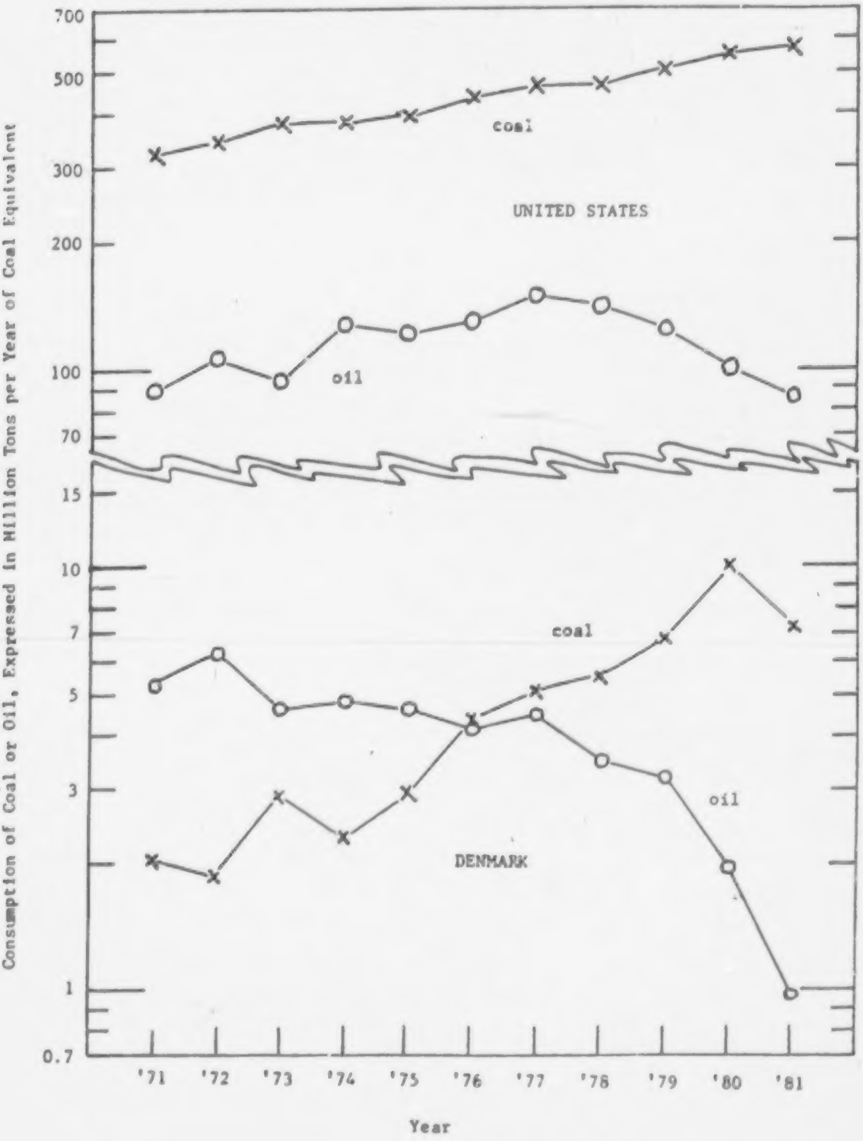
Technologies for generating electricity from coal are well known, and available readily to anyone almost anywhere in the world.

One small country, Denmark, has set the standard for what can be done in substituting coal for oil in electricity generation. As Figure 1 illustrates, our own record in this respect is poor in comparison. Denmark's incentive, of course, was great: it has no domestic source of fuel other than straw, and must import almost everything that it burns.

I frequently run into the comfortable opinion that conversion of a power station designed for oil to coal firing is "impossible." Yet in 1979 I saw an oil-fired boiler for 300 megawatts of electricity undergoing conversion at Odense, Denmark. My hosts there said that they were paying a bit more than $100 per kilowatt for the work. I doubt if many American power engineers would find what was done at Odense very congenial. In order to enlarge the combustion space, extending it downward, the Danes had to dig a pit something like 20 feet deep with pumps in it to keep out ground water. Nevertheless, I am sure that the power company at Odanse is enjoying an excellent return on its investment for the conversion (even taking into account capital losses during the work because generating equipment was idle).

Figure 1

Coal and Oil for Electricity in the United States and Denmark



Residential Space Heat and Hot Water

In 1978, nearly one million barrels per day of oil, on average, provided residential space heat and hot water in the United States. By 1981, this had declined by 30%; but coal did not pick up much of this business. This was not because the coal option is the most expensive! It was mainly because the coal option is simply not visible in our country.

New Zealand and Great Britain provide two examples of nations that never abandoned coal for space heat and hot water. Each nation provides us with a model of what must be present if a coal market for residential heat is to thrive:

- mining establishments, distributors, and dealers which supply quality-controlled "domestic solid fuels" certified by authority of government — i.e., either smokeless solid fuels or bituminous coals of a grade and quality suitable for burning smokelessly in smoke eaters;

- manufacturers, dealers, and installer/maintainers of appliances certified, by authority of the government, to burn appropriate fuels smokelessly;

- an advisory service working in cooperation with an appliance testing and development laboratory.

In both countries, funds for the advisory service come from the coal mining industry — many small, privately owned companies in New Zealand, and the National Coal Board in Great Britain.

New Zealand's or Great Britain's coal advisory service helps a buyer of equipment decide what best will fit his needs: i.e., what furnace he should buy in light of the several varieties of coal that his local market offers. The advisory service helps equipment manufacturers as well. In each country, a number of firms manufacture household coal furnaces. The firms are small and cannot afford to provide much by way of education of the public concerning appropriate uses for the furnaces they build, nor even to do much testing of their own furnaces, let alone to develop radically improved designs. In both countries, the advisory services work in cooperation with laboratories which play dual roles: testing equipment for efficiency and emissions of pollutants, and developing improved designs.

In the United States, efforts to find improved furnace designs effectively ceased in about 1950. It is not surprising that both New Zealand and Great Britain now have furnace designs significantly better than anything we know here — more compact; more convenient; and far cleaner in respect to both dust inside a home and pollutants emitted to the atmosphere.

> The annual budget of the National Coal Board's small-coal-furnace development team at Stoke Orchard has never exceeded $1,000,000. I would be surprised to hear that the Board's advisory service costs more than a few million per year.

In each country, a householder may choose either an appliance to burn a smokeless solid fuel or an appliance certified to burn a particular, certified, quality-controlled bituminous coal smokelessly. The appliance for the smokeless fuel is cheaper, but its fuel is more expensive. If the householder selects an appliance to burn a particular bituminous coal, both he and his coal dealer sign affidavits having force of law pledging that the appliance will never see any other coal.

In Part II, I will address the difficult question, will it be best to try to revive supplies of smokeless solid fuels in the United States, or to develop supplies of quality-controlled bituminous coals and also appliances which can burn these coals smokelessly?

I will also show what bargains small coal stoves are when they are used to provide supplemental household heat — from the nation's viewpoint as a way to reduce our consumption of oil, and from the individual owner's viewpoint as well. I am speaking of stoves at ratings around 30 thousand Btu per hour, for example, which would be operated to heat only a part of a house and would allow a householder to operate his central heating system only in the severest cold weather. A cheap source of supplemental heat touches interests of many of our nation's citizens, especially those having low incomes. In the latter 1970s, millions of homes acquired wood stoves to provide supplemental heat. Today, with wood stoves already in wide use wherever wood is readily available, many households are trying to cut their heating bills by buying kerosine heaters.

Commercial and Industrial Space Heat and Hot Water

In 1978, the United States burned nearly one million barrels per day of oil, annual average, to provide space heat and hot water in commerce, agriculture, and industry. By 1981, this had declined nearly 50%; but again, coal picked up very little of the business. Nearly all of this oil was burned in units smaller than 20 million Btu per hour; much of it, in units smaller than 10 million Btu per hour.

Until recently, I did not fully appreciate the advantages of coal for this service. When we think of costs, we tend to remember those for much larger boilers providing high-pressure steam, not hot water. The larger boilers need elaborate pollution controls, and costs for operating labor are high.

Although significant improvements have appeared in furnace designs overseas in the years since we stopped paying attention, nevertheless, coal-fired furnaces providing hot water have changed the least from what was familiar to fuels engineers 30 years ago. An underfeed stoker or a traveling-grate stoker does not need much in the way of pollution controls to meet the requirements of most jurisdictions, if a supply of low-sulfur coal can be assured. Also, many jurisdictions will permit unattended operation of water heaters at ratings where the jurisdictions would require continuous attention of a steam boiler by a skilled operator.

> A fluidized-bed furnace requires expensive and finicky controls to eliminate particulate emissions, and is probably not well suited to provide space heat and hot water except at ratings beyond about 10 million Btu per hour.
>
> > Not everyone will agree with this judgment. Groups in New Zealand, Great Britain, Nova Scotia, and Denmark are working on fluidized-bed furnaces at even the tiny scale for heating an individual dwelling. I believe that these groups have not yet faced up to the problem of devising affordable, robust controls on dust emissions.
>
> The fluidized-bed furnace can use limestone to capture sulfur, and will of course be more competitive in states like Ohio, where local coals are high in sulfur, than in states like Virginia, with supplies of low-sulfur coal.

New Zealand and Great Britain have infrastructures supporting markets for what we might call "commercial coal" — i.e., coal for space heat and hot water in commerce, agriculture, and industry — and these infrastructures merge with those supporting markets for "domestic solid fuels." Many firms manufacturing household furnaces also supply furnaces at ratings up to a few million Btu per hour. A customer can buy a number of grades of quality-controlled commercial coals. The same advisory services that certify solid fuels and appliances for the household market also guard quality of commercial coals and equipment.

Although New Zealand and Great Britain provide excellent models of what we should try to achieve here, nevertheless, the experience of Denmark provides better instruction as to how we should go about setting up an appropriate infrastructure to promote sales of commercial coal. Both New Zealand and Great Britain have enjoyed assured supplies of many types of quality-controlled commercial coals. Denmark, like the United States today, does not have such supplies. What Denmark receives from the world coal market represents a wide range of coal types and qualities. Danish experience coping with a variety of coals is closer to what we will experience in developing markets for commercial coals.

With financing from Denmark's goverment, the Dansk Kedelforening — Danish Boiler Owners' Association — promotes use of commercial coal in Denmark. The Association tests furnaces for efficiency and emissions when burning a wide range of coals. It helps a member who has had the misfortune to acquire a bad coal. It sets up trials of furnaces of advanced design in practical service in the field, and monitors their performance. I believe workers at this Association are the world's leading experts in selecting combustion equipment for a specific coal — and also in making the equipment function as well as humanly possible when this coal is not available and another coal must be used. Their experience will help us extend the range of coal types and qualities available here to a wide variety of commercial, agricultural, and industrial heat needs.

Even so, a major problem for the United States is how to ensure a steady supply of coal of type and quality that an individual owner needs. The owner will rarely be able to analyze coals he receives for quality; he must trust that his supplier has performed the analysis and has guarded his interest.

In Denmark, both Shell and British Petroleum have taken on the responsibility of distributing quality-controlled commercial coals. Norcem, Norway's cement company, has taken on this job in Norway and southern Sweden, and has engaged Dansk Kedelforening to help it sell commercial coal.

Ways Government Should Help

I believe that significant coal markets could be developed in the 1980s for space heat and hot water with help from government. It should:

1. Establish regional centers at selected Land Grant Universities which play the role of New Zealand's and Great Britain's advisory services. Each center would focus on its region's coals and heat needs, ranging from around 10,000 Btu per hour for a domestic hot water heater to commercial sizes on the order of 20 million Btu per hour.

2. Provide money for each center to conduct field trials of furnaces at sites of selected users. My choice for Virginia would be tests of several approaches to replacing propane as heat in chicken farms. Owners of farms would cooperate enthusiastically with Virginia Tech's Extension Agents. I do not think we could find a better way to increase coal's visibility in our Commonwealth as an energy option at the scale of roughly 0.5 to 3 million Btu per hour.

3. Provide start-up money for qualified distributors of coal — institutions capable of negotiating agreements to purchase coal and of conducting laboratory tests on coals they receive, to ensure quality control of the coals they sell. The farm cooperative is an example of the sort of institution I have in mind.

4. Provide low-cost insurance to a purchaser of a small coal furnace against several uncertainties:

   (a) that a particular furnace is a lemon in respect to either efficiency or life or emissions;

   (b) that an owner's fuel distributor finds it impossible to provide a reliable supply of solid fuel of the quality which his furnace needs; or

   (c) that future environmental studies will make it imperative that an owner abandon coal for the use for which he bought his furnace.

5. Encourage development of supplies of manufactured smokeless solid fuels.

> Both New Zealand and India have recently built installations to manufacture smokeless solid fuels from subbituminous coals not unlike those of Montana, Wyoming, and Alaska.
>
> Jewell Smokeless Coal Company of Van Sant, Virginia, has developed and is using a new coke oven that is clean and can be built at low capital cost. A problem, however, is what to do with combustible byproduct gases which the new oven produces. A solution that makes good engineering sense is to burn the gases in equipment generating baseload electricity — i.e., electricity co-generated along with coke manufacture. This solution also makes good economic sense, when viewed from society's interest, but is not interesting to a coke producer today because power companies do not wish to purchase such co-generated electricity except at prices so low as to be unattractive. Laws are now on the books requiring power companies to purchase co-generated electricity from tiny installations.

6. Extend laws requiring purchase of co-generated electricity to the larger scale of operation which manufacture of smokeless fuel represents.

> Capital investment to produce this co-generated electricity is a bargain in comparison with cost to erect large coal-fired baseload electricity stations.

7. Encourage revival of anthracite mining in northeast Pennsylvania. Time is short for this, since the men who now run the industry are elderly.

Heat for Oil Production

Several types of high-velocity fluidized-bed combustion furnaces are being tested at a large scale to provide steam for secondary oil recovery. Success in these tests could lead to significant sales of coal — especially low-grade coals now of little interest to coal markets.

Process Heat in Petroleum Refineries

Several per cent of the oil that our nation consumes is burned to provide process heat in petroleum refineries. This is a lot of oil, burned in a relatively few locations! It is a prime target for coal! But it is not an easy target.

No good system for using coal to provide refinery process heat is yet in view. The problem is that a typical refinery today has a score or more of furnaces scattered over a site perhaps one by three miles in extent. It is difficult to imagine placing a score of coal-fired furnaces at the locations of existing furnaces. Getting coal to each furnace, taking ash away from it, and providing individual pollution controls at each furnace looks like an unattractive proposition. Some thought has been given to using an organic liquid, such as "Dowtherm," to carry heat from a central coal-fired furnace to a number of scattered process heaters; but such a liquid cannot provide heat at some of the higher temperature levels which the petroleum refiner requires, and systems using a liquid have high costs for maintenance, because carbon deposits tend to form inside piping.

My colleagues, Y. A. Liu and Kenneth Konrad, and I, in the Department of Chemical Engineering at Virginia Tech, are exploring, with modest support from an oil company, a new idea for distributing heat from a central coal-fired furnace to scattered process heaters. We would carry the heat using hot powder, moving it to distant points in the refinery by means of a novel technique for conveying a powder. We would use a fluidized-bed furnace to heat the powder with coal.

If we are right, we believe that a project to convert petroleum refineries to coal heat could achieve significant results before 1990. If our preliminary findings are encouraging, we plan to seek governmental funding to permit our research to move forward with speed.

Process Heat in the Chemical Industry

A system developed for the petroleum industry might find some use in the chemical industry as well. Market penetration could not be expected to be as rapid, for process heaters in a typical chemical manufacturing complex are far greater in number and smaller in size than the process heaters in a refinery.

Process Heat in the Steel Industry

The steel industry needs gaseous fuel for its process heat. An urgent need is air-blown coal gasification equipment simply to produce low-Btu gas at the scale this industry requires. Historically, before natural gas became available, the industry used tens of thousands of air-blown "gas producers" making low-Btu gas. It is hard to imagine the industry wishing to operate so many individual units of such small scale again.

Both Westinghouse and the Institute of Gas Technology (IGT) have fluidized-bed gasification systems under development, about which I know little in detail, that may lead to equipment appropriate to the steel industry's needs. (I refer to IGT's U-Gas development, not to Hygas.)

Westinghouse's and IGT's approaches are similar in some important and critical respects. I believe they should have have competitors, and increased governmental funding in this area of coal hardware development will be appropriate.

A French competitor appears to me in principle to offer an opportunity for a coal gasifier more robust than either the Westinghouse or the U-Gas approach may provide — i.e., more forgiving of both coal type and lack of skill or diligence on the part of an operator. This is the "Ignifluid" boiler, invented by the late, great French engineer, Albert Godel, and manufactured by Fives-Cail Babcock of Paris. Before Godel died in late 1974, he experimented with a modification of his boiler to provide low-Btu gas instead of steam. I understand these experiments are now going forward again, but probably at a slow pace and low priority. I am not in touch with the current situation. Learning more about Fives-Cail Babcock's progress and plans should be an item of high priority for our nation's energy planners. I think it likely that, upon understanding the opportunity, they may wish to lend support, either to speed up the work or to set similar work in motion here.

Process Heat in Other Industry

Much of the process heat used by industry is in form of steam. Coal can displace oil or gas for this service in a number of ways, in competition with one another:

- installation of a new coal-fired boiler, using —
    - — conventional pulverized-coal combustion equipment;
    - — conventional traveling-grate, underfeed, and spreader stokers;
    - — the Ignifluid boiler;
    - — several new fluidized-bed combustion approaches using limestone to capture sulfur — some developed in the United States; others, abroad; and
- retrofit of an existing oil-fired boiler by several techniques —
    - — coal-oil and coal-water slurries, and
    - — a clever new burner for pulverized coal and oil or gas, fired separately at about 75 parts of coal per 25 parts of oil or gas, developed by Hamworthy Engineering Ltd. of Poole, England.

I do not believe we will see a winner-take-all outcome of the competition. Each of these approaches will probably find a niche which the market-place will identify. I believe that special governmental support for one particular approach neither would be wise nor would have much affect upon the outcome. Governmental support should be general, in respect to the total market opportunity for all acceptable ways to burn coal. Let me stress that conventional stokers are not all that bad, although their role in the market depends more heavily than do several of the newer approaches upon developing supplies of quality-controlled coals.

I should say a bit more about both Hamworthy's new burner and the Ignifluid boiler.

Hamworthy conceived its new burner in September 1980, tried it out in its own steam plant early in 1981, and made the first commercial installation in March 1981. A number of dairies in southern Ireland are using the system, firing coal and oil, at heat output ratings of 20 to 30 million Btu per hour. Conversion of a unit at 30 million Btu per hour cost $400,000, including a second-hand coal-grinding plant to provide pulverized coal. This works out to about $45 per kilowatt (thermal output) for the conversion. I should note that the depressed state of the world's cement industry means that a lot of coal-pulverizing equipment can be had at practically scrap value.

Fives-Cail Babcock has build some 30-plus copies of the Ignifluid boiler at sizes up to 420 million Btu per hour. Its outstanding features are (1) ability to burn almost any grade of coal, regardless of ash content, with little expense for coal preparation other than simple crushing, and (2) ability to meet pollution standards for particulate emissions with simple, cheap, robust means of control. Together with Niro Atomizer's dry process for capturing sulfur dioxide from fuel gas, I believe the Ignifluid would be a strong competitor for the industrial heat market if it were visible here. But purchasers of steam boilers are not the most venturesome among our technologists. One must travel 3,000+ miles to see an Ignifluid, and only a relatively few of us have yet taken the time to make the journey, to study the Ignifluid, and to appreciate its advantages.

There is an important role for government in making the Ignifluid visible: It should purchase an Ignifluid for the heating plant of a Land Grant University, where engineers could test it on a number of coals and make it available for visitors from industry to study.

Railroad Locomotives

In the Summer of 1980, William B. Benson and Ross E. Rowland, Jr. of American Coal Enterprises ("ACE") assembled a team in the basement of Benson's home in Akron, Ohio, to design a state-of-the-art coal-fired steam locomotive. The team had several old-timers who were employed by locomotive or boiler manufacturing firms in the days of steam locomotion, and also, most importantly, Livio Dante Porta of Argentina, who in 1958 invented a new, clean combustion technique which has been used successfully in Argentina's railways for 25 years, and more recently, in South Africa.

ACE is a member of a recently organized joint venture partnership, Coal-Oriented Advanced Locomotive Systems ("COALS"), which will commence engineering work this Fall toward production of prototype locomotives. Other members of the partnership are Burlington Northern Railroad, Chessie System Railroads, and Babcock & Wilcox/McDermott International. *Barron's Weekly* estimates that the partnership will spend about $40 to $60 million on its COALS project. The two railroads in the partnership believe that their internal rate of return on invested capital will be greater than 50%. This is for complete conversion of their fleets from diesel to steam, including setting up both maintenance shops and systems to supply coal and water to engines and to dispose of ash.

Metallurgical Coal to Manufacture Coke — for Domestic Use and Export

Recently, a response of the steel industry to depressed markets for its product, both in the United States and Europe, has been to retire and dismantle many antique coke-oven installations. When the industry revives, coke will be short on the world market. My friends at Jewell Smokeless Coal Company believe there will be a coke shortfall between 10 and 20 million tons per year before the end of the 1980s.

I mentioned earlier this company's new technique for manufacturing coke. In essence, it is a modified beehive oven, but without the terrible pollution which this type of oven put out in its historic form. Not only does the new oven cost far less than the traditional slot oven, but also it requires smaller outlays to eliminate pollution. Jewell does its own engineering and construction, and even manufactures many of the special devices that its oven requires. Jewell can erect and commission new oven capacity in eight months. It should be able to do well on the world coke market as demand recovers.

I am not expert in coke manufacture, but I will give you my understanding of an important difference between Jewell's new oven and the slot oven which the world's steel industry now uses to manufacture substantially all of its coke.

In a slot oven, coal to be carbonized is placed in a tall, narrow chamber with refractory walls. Gas is burned in a space outside each wall, and heat from this combustion passes through the wall into the bed of coal. The coal swells, and pressure develops within the carbonizing coal because the walls resist lateral expansion of the coal. This pressure is important for coke quality in most steel mills around the world. Most mills buy a number of coals, and blend them before charging them into a slot oven. Expertise has developed which permits the operator of a slot coke oven to tailor his coal blends so that his coke has the strength which a modern blast furnace requires, even though only a small fraction of the coals in his blends are of highest metallurgical quality.

In Jewell's new oven, coal to be carbonized is placed in a shallow layer across the floor of a wide refractory chamber. The coal layer is heated both from above and below. Heat from above is by direct radiation from combustion of volatile matter that evolves from the carbonizing coal. Heat flows into the coal from below across the refractory floor from a chamber beneath the floor where further combustion of volatile matter occurs. No internal pressure is generated within the coal layer, as it carbonizes, and I understand that only coals of high metallurgical quality can be used. Jewell is making coke of high strength from a metallurgical coal that is typical, I believe, of the metallurgical coals of southwestern Virginia, southern West Virginia, and eastern Kentucky.

We must be ready for a major opportunity that should arise before 1990 for miners of metallurgical coals in these states, for both domestic and overseas sales of cokes of blast-furnace grade.

Exports of Steam Coal

I have mentioned the buildup of coal consumption in Denmark. More recently, a buildup in Italy has occurred. I believe that this story will be repeated all over the world.

Customers need service, however; small customers, most of all. Our coal industry will fare poorly on the world coal market, especially for domestic and commercial fuels, if it cannot also export equipment — or set up manufacturers of equipment — suitable for burning our coals to serve a variety of heat requirements. I should note in this connection that eastern bituminous coals are very different from most coals marketed by our competitors. Purchase of a device suitable for one of our coals will often tie a customor to this coal, and shut out overseas competition. And vice versa, if the purchase is of a device suitable only for a coal that we cannot supply!

For this reason, any effort exerted by the government to promote use of coal in small furnaces domestically can also help overseas sales by providing information on design and use of furnaces appropriate for our coals.

A Danger to Exports of Metallurgical Coals for Manufacture of Coke

I mentioned earlier, that the operator of a slot coke oven has sophisticated techniques to blend coals for coke strength. It is even possible to make good coke from a blend of coals none of which could individually produce coke suitable for the blast furnace. Japan has been the main beneficiary of these techniques, and I have seen coke ovens in Japan which process blends of more than 20 coals. Our steel companies also use the techniques, but seldom use more than a relatively few coals in their blends.

Just in the past decade, a deeper scientific understanding of the coking process has developed. I believe that Professor Harry Marsh of Newcastle University in England is responsible for the scientific breakthrough that has led to this understanding. There has been a parade of post-Doctoral students from Japan to his laboratory, and at least one of his students now occupies a professorial chair in a university in Japan. Others are in Japanese industry. Our own steel industry has learned from Marsh, but no one to my knowledge is putting this new understanding at the service of our coal mining industry.

There is a danger: Japanese researchers are working at top speed to put the Japanese steel industry in a position where it will no longer need to import our metallurgical coals.

They have already gone far along this path, and I believe that at least part of the decline in our overseas sales of metallurgical coals is accountable to work by scientists, not to cutbacks in steel production.

Some Japanese steel companies are already adding small amounts of Australian subbituminous coals to their coke-oven blends — something few would have thought possible ten years ago. The trick is to admix petroleum pitches of certain special qualities with the Australian coals. There are problems with this trick: (1) the pitches are high in sulfur, and this limits the amount of subbituminous coal that can be used; and (2) petroleum pitches of the special qualities needed may not be available one or two decades from now. Accordingly, Japanese scientists are working hard to find a way to produce low-sulfur pitches of suitable quality from coal. A success along this line might well eliminate need for United States metallurgical coals altogether.

What is needed is defensive research paralleling the offensive research now underway in Japan. If we do not understand the new science of coke making, we will not understand special qualities which our coals must surely possess. With such understanding can come instruction by us to manufacturers of coke all over the world — instruction that will show them how they can make coke at lowest cost if they use our coals to best advantage in their blends.

It is of course the nature of defensive research that it does not always pay off. But we must try, and the cost of the research will be infinitesimal in comparison with what is at stake.

It is obvious that coke research at our steel companies will not provide what we need. This research, quite properly, is to serve economic interests of their stockholders, not interests of the coal mining industry.

I believe that the research should be done at our universities, so that students can learn skills which industry will need. Coal science is not glamorous, and success is uncertain. I would comment, however, that the science is apt to lead to something useful, even if its main objective is not reached. Science will be needed, for example, to exploit fully the opportunity for coke sales based upon Jewell's new coke oven.

Funding authorities for university research in Washington have tended to turn deaf ears to arguments for research of this type. Professor Walter Hibbard and I, with much-appreciated help from Harry Marsh of England, have attempted, without success, to obtain funding to start coke research at Virginia Tech. Neither of us, of course, have long careers as researchers on techniques for coke manufacture, and I have the impression that Washington found it easy to turn us down on that ground, not giving us credit for our good track records in other fields.

Bituminous Coal to Manufacture of Smokeless Solid Fuels

I have mentioned Jewell's new coke oven. It could make smokeless solid fuels of adequate strength from a wide range of bituminous coals of non-metallurgical grades. Equipment using traveling grates and rotating hearths to manufacture coke for the chemical industry — such as Peabody Coal Company's traveling grate furnaces at Columbia, Tennessee — can also convert caking bituminous coals into smokeless solid fuels. For western and Alaskan subbituminous coals, a designer may consider a wider selection of carbonization equipment.

Other processes can be visualized that would convert bituminous coals to smokeless fuels with only mild heating, rather than heating to the higher temperature reached in Jewell's oven. I have ideas, and no doubt other inventors would come forward, to exploit advances in engineering in the several decades since manufacture of smokeless solid fuels was a major item on the inventor's agenda. Such thinking should be encouraged.

In all cases, thought must be given to a co-product. I have mentioned that co-generated electricity is a possibility. It is also interesting to consider byproduct synthesis gas — or synthesis gas plus a little electricity. I think it highly probable that a "Coalplex" could ship both smokeless solid fuel and methanol or synthetic gasoline at lower prices than two separate facilities could afford to charge for their products.

Today's Hearing relates to the 1980s. Let us, however, look just a little beyond 1990. Hawaii, Japan, and many other constituencies will not be able to afford to use oil for space heat and hot water much beyond 1990 or 2000. I foresee coal "refineries" in the East, processing low-sulfur bituminous coals, and in the West and Alaska, processing low-sulfur subbituminous coals and lignite — shipping smokeless solid fuels and liquid fuels to the World.

Even today, one of the best ways our country could assist Third World nations that lack fossil fuels would be to ship them smokeless solid fuels. Many of these nations face the choice of either importing kerosine for cooking, at great cost to their economies, or of making deep inroads into their forests to produce charcoal for cooking, at great hurt to their own climate and to the world's. Even a nation with coal is granted only a poor third choice: in India, for example, many poor women breathe smoke from the bituminous coal they burn when they cook dinner — richer folk use kerosine or charcoal. India has built at least one large plant — designed in India! — to convert subbituminous coal to smokeless solid fuel for cooking. India's resources are not sufficient to build many plants of this kind quickly. We could help India and other Third World nations as a spin-off from an endeavor that would also help our coal industry and our own consumers of space heat and hot water.

Part II. *SMALL COAL FURNACES FOR SPACE HEAT AND HOT WATER:*

The Neglected Option

The United States burns about 1.25 million barrels per day of oil, on average, to provide space heat and hot water. In dwellings, some 20 million furnaces consume about 700,000 barrels per day. In commerce, agriculture, and industry, some 600,000 small oil furnaces burn 500,000 barrels per day. Of these latter furnaces,

> 331,000 are smaller than 400,000 Btu per hour of heat output (i.e., smaller than 117 kilowatts);
>
> 194,000, between 400,000 and 1.5 million Btu per hour (between 117 and 439 kilowatts);
>
> 81,000, between 1.5 and 10 million Btu per hour (439 kilowatts and 2.93 megawatts); and
>
> 12,000, between 10 and 25 million Btu per hour (2.93 and 7.3 megawatts).

Energy planners have neglected to consider how direct combustion of coal in small furnaces might replace this oil.

Modest targets might be to back out roughly 250,000 barrels per day, on average, from oil furnaces smaller than 117 kilowatts, and roughly another 250,000 barrels per day from oil furnaces between 117 kilowatts and ca. 7.3 megawatts. Meeting both targets would call for production and distribution of roughly 40 million additional tons per year of coal.

This Part II of my testimony treats

- economic incentives for a national effort to meet these targets,
- environmental questions to be addressed in planning the effort, and
- tactics that the effort might use.

I address a narrow point. I will not discuss, for example, the coal that might be used in small furnaces to back out gas or electricity, although you will recognize instances where economic incentives exist for these substitutions as well as situations favoring the substitution which I will treat in detail.

Economic Incentives to Use Coal for Space Heat and Hot Water

I can give only an impressionistic picture of what the economics of small coal furnaces in the United States might become

- if a diverse line of appliances were to become available for a variety of heat needs, and

- if an infrastructure to support small-scale coal combustion were in place: manufacturers, dealers, and installer/maintainers for coal furnaces; suppliers and distributors of quality-controlled coals.

I sketch this picture here; an Appendix gives further details. My sketch furnishes examples illustrating the economic incentives for small coal furnaces to provide

(1) supplemental heat in a home —

— e.g., to keep a living space warm while leaving the rest of the house at a temperature sufficient to prevent water pipes from freezing; or to replace an oil heater that supplies sanitary hot water;

(2) primary heat in a home;

(3) agricultural, commercial, or industrial space heat and hot water.

In my examples, I take $1.00 per gallon as the price of heating oil. I would remind you, however, that oil sold at $1.20 per gallon just a year ago. I believe it will sell at this price again, and indeed, I am sure we can all imagine scenarios in Middle Eastern politics that would send the price far higher still. (In my Appendix, I give economic data for oil at $1.20 and $1.40 per gallon, as well as for oil at $1.00.)

(1) *Supplemental heat in a home:*

Let no one imagine that rural and small-city American households will not embrace coal for supplemental heat, if the coal option were to become available. A coal stove is a lazy man's alternative to a wood stove. Sales of wood stoves, running at ca. 1 million per year for several years, have fallen away as wood energy penetrated wherever wood is available. Recently, a boom in kerosine heaters witnesses the householder's desire for a heat supplement to keep selected spaces warm while saving oil at his central furnace.

An example to illustrate the incentive for supplemental coal heat in a home:

> A simple, hand-fired stove to burn smokeless fuel at $120 per ton, replacing oil at $1.00 per gallon, could be paid for from fuel savings in about 20 months if heat is needed at full rating of the stove for 2,000 hours per year.
>
> The payout time for the stove would be about 10 months if it burns bituminous coal at $80 per ton. *This option will emit smoke!*

Another example:

> A small, sophisticated, hand-fired stove to burn bituminous coal "smokelessly" would have a payout time of about 26 months if operated for 2,000 hours per year, with fuel prices as given above. Such stoves exist in England for heating water, as well as developmental designs for heating air.

(2) *Primary heat in a home:*

A larger household furnace burning bituminous coal "smokelessly," with automatic feed of coal following heat demand, would afford a payout time of about 41 months, at the above fuel prices, if the furnace operates at full rating for 1,000 hours per year. A well-insulated dwelling at Blacksburg, Virginia, would need heat equivalent to about 1,000 hours of operation at full output of the furnace typically provided in such a dwelling. It would consume ca. 400 gallons of oil in a heating season if the house has ca. 2,000 square feet. A similar dwelling in Duluth, Minnesota, might use about 800 gallons, and its owner could convert to coal at a payout time of about 20 months.

(3) *Agricultural, commercial, or industrial space heat and hot water:*

Examples to illustrate the attractiveness of coal for small agricultural, commercial, and industrial space heat:

> Underfeed stokers, with automatic feed of coal following heat demand, but with manual removal of ash, would enjoy payout times between about 15 and 32 months if operated at full rating for 2,000 hours per annum to burn coal at $50 per ton, replacing oil at $1.00 per gallon. This is for ratings between 900 kilowatts and 4.5 megawatts heat output; the higher ratings would use multiple furnaces.
>
> Chaingrate stokers, with automatic feed of coal and disposal of ash, would afford payout times between 7 and 10 months if operated at full rating for 4,000 hours per annum to burn coal at $40 per ton, replacing oil at $1.00 per gallon. This is for ratings between 4.5 and 9.0 megawatts heat output.

The above estimates of payout time provide a crude impression of an individual owner's incentive to acquire a small coal furnace. What is the incentive for a revival of small-scale coal combustion, when viewed from a national perspective?

Let us examine the capital costs for environmentally benign equipment to back out oil now being burned to supply space heat and hot water. I tabulate below some very approximate capital costs to provide equipment to replace one barrel per day of oil, annual average, now used for these needs.

> In the examples below, capital costs include the following investments to develop new supplies of solid fuel, as appropriate:
>
> $2,000 for a new bituminous coal mine; or
>
> $8,200 for a either a new anthracite mine or new bituminous mine together with a new coke oven of the type developed by Jewell Smokeless Coal Company — by coincidence, the investments for these alternative routes to smokeless solid fuel are about the same.

Supplemental household heat for 2,000 hours per year from a small handfired stove burning smokeless fuel	$16,700
Supplemental household heat for 2,000 hours per year from a small handfired stove burning bituminous coal smokelessly	$20,300
Primary household heat for 1,000 hours per year from an automatic furnace burning bituminous coal smokelessly	$31,300
900 kilowatt underfeed stoker, 2,000 hours per year	$16,300
1.5 megawatt underfeed stoker, 2,000 hours per year	$11,900
4.5 megawatt installation using underfeed stokers, 2,000 hours per year	$ 8,600
4.5 megawatt chaingrate stoker, 4,000 hours per year	$12,100
9.5 megawatt chaingrate stoker, 4,000 hours per year	$ 9,300
Synthetic oil manufactured from coal — synthetic liquid petroleum; substitute natural gas; methanol — approximately	$78,000
New supply of electricity, plus a new appliance for electric resistance heat used 2,000 hours per year — approximately	$96,000

This is not, of course, the capital cost to back out a barrel per day of oil new being using to generate electricity.

> The latter cost is about $40,000 if a new coal-fired electricity station must be built; but there must surely exist some oil-fired stations where coal could replace oil, at least to an extent, at investments far lower than this.

From these figures, total capital cost to meet our 250,000 barrels per day target for replacing oil now used for domestic heat could be, very roughly, about 5 to 8 billion dollars.

Capital to replace 250,000 barrels per day burned for space heat in agriculture, commerce, and industry could be, very roughly, 3 to 4 billion dollars.

These sums compare to the 20 or 25 billion needed for the synthetic oil or electricity option to replace 250,000 barrels per day.

SMALL COAL FURNACES ARE BARGAINS!

They also represent widely dispersed economic activities, involving much small-scale enterprise. They can be provided at far less pressure upon our limited resource of engineers and institutions qualified to participate on mega projects for manufacturing synthetic oil from coal, oil shales, bitumens, and the like.

Purchasers of coal furnaces, however small, deserve terms of financing and tax incentives at least as attractive as those afforded to builders of mega projects for either synthetic oil or electricity.

Environmental Questions To Be Addressed

London, like Pittsburgh and St. Louis, suffered frequent smogs in the bad old days of coal smoke. Britain's experience since passage of that Nation's Clean Air Act of 1956, however, has taught its citizens what Americans have not learned — that small appliances burning solid fuels can be clean and convenient. London no longer has smogs, yet coal still provides London with much of its domestic and commercial space heat and hot water.

What emissions of air pollutants from small coal furnaces can we expect, and what will be their environmental effects? Let me first take up the question of "smoke," and later take up sulfur dioxide.

**** SMOKE ****

There is no question that smoke is harmful to human health. Britain's clean air legislation focuses on eliminating smoke. For furnaces smaller than ca. 100 kilowatts, we must look to Great Britain for state-of-the-art "sound practice" in coal combustion. No research has been conducted here on improved practices for such combustion since about 1950.

Many stoves and furnaces smaller than 100 kilowatts in Great Britain burn solid fuels that have been certified as smokeless by a standard test. Little is known in detail of the emissions of dust from individual furnaces of this type, but they are surely very small.

In the past twenty years, Great Britain has developed improved domestic appliances burning bituminous coal "smokelessly" — i.e., emitting very little dust or tar aerosols. "Smoke eaters" at ratings from ca. 4 to 12 kilowatts and underfeed stokers at ca. 44 to 60 kilowatts are available or in advanced stages of development. Britain's clean air legislation requires that smoke emissions from the former run less than about 1 gram per kilowatt-hour of heat output, while emissions from the latter must run less than 0.44 grams per kw-hr. The starting point in the thinking that leads to environmental legislation and regulation in Great Britain is the present rather than a theoretical goal, and these limits on smoke emissions are an expression of what British fuels engineers recognize to be state-of-the-art "sound practice."

Recent tests of American underfeed stokers developed before 1950 suggest that these stokers would not meet the standard set by Britain's clean air legislation, but fortunately, the test emissions were not far beyond the British standards. Continued sales of American stokers, even at volumes far beyond the current sales of a few thousand units per year, could threaten no environmental harm during the relatively few years that would be needed to modify the designs to bring their emissions within the limits set in Great Britain. About fourteen years ago, British engineers developed relatively simple changes in a typical 1950-vintage American stoker which reduced its emissions to Britain's standard. Dennis Jaasma and his students in the Department of Mechanical Engineering at Virginia Tech have measured emissions from a British smoke eater burning a Virginia low-sulfur coal, and found them to meet Britain's standard. Jaasma's students had to use a poker more often than might be desired, and we are not certain that this particular smoke eater could be a success here. Nevertheless, we can be confident that a line of appliances to burn American bituminous coals can be quickly developed that will emit no more smoke than appliances which the British public can now purchase.

It is important to understand that the low emissions of smoke from small British appliances for bituminous coals are achieved simply through clever combustion design. There are no control devices to capture dust. The magnitude of this technological achievement can be appreciated when one realizes that the British standard of 0.44 grams per kw-hr for an underfeed stoker at 44 kilowatts is appreciably less than the 1.7 grams that Britain would allow for a boiler of 1.75 megawatts; and, moreover, the boiler would need dust-collection devices in order to meet the 1.7-gram standard! The higher standard for the boiler, of course, makes a certain sense because it must have a tall chimney to disperse sulfur dioxide.

It is also important to note that just one small research team, working under William Kaye at the National Coal Board's Central Research Establishment at Stoke Orchard, near Cheltenham, produced Britain's achievement in small-scale coal combustion. Kaye's group never had a budget beyond about $1 million per year, and never comprised more than 10 professionals.

Standards on smoke emissions from commercial and small industrial boilers tend to run at lower values in the United States than in Great Britain, and it is hard to fault the political process that has led to these lower standards in light of the proven connection between fine particulate matter and human health. The State of Virginia, for example, would require emissions less than about 0.58 grams per kw-hr output at a small coal-fired boiler installed in Virginia's suburban counties near our National Capital.

Commercial and small industrial boilers larger than a few hundred kilowatts will need to be equipped with good dust collection equipment. It is hard to generalize, but I believe that the new fluidized-bed furnaces, burning coal in a fluidized bed containing water tubes which keep the bed at a temperature below about 900°C, will need fabric filters. I believe spreader stokers and pulverized-fuel furnaces will need either fabric filters or electrostatic precipitators. From data which I have recently seen for emissions from a 4.6 megawatt chaingrate stoker operating in a greenhouse in Norway, burning Eastern U. S. bituminous coal, I believe that this equipment also will usually require a fabric filter to meet Virginia's standard, unless a supply of coal of high quality can be assured. From other Norwegian data, for a 900 kilowatt underfeed stoker burning U. S. bituminous coal, I believe that this stoker could meet Virginia's standard simply with installation of a mechanical dust collector, such as a multicell cyclone gas-solid separator.

Unfortunately, a fabric filter cannot be used with a coal furnace where rapid, large swings in heat demand frequently occur — for example, to supply heat to a greenhouse. Moreover, both fabric filters and electrostatic precipitators require careful, skilled attention. On the other hand, underfeed and chaingrate stokers are less able to accommodate themselves to a wide range of coal types and especially mineral-matter content than are fluidized-bed furnaces and spreader stokers.

This makes an examination in the United States of the Ignifluid boiler important. This boiler, developed by Fives-Cail Babcock of Paris, France, is a robust fluidized-bed-combustion device, already in wide commercial use in France and countries with trade relations with France. It is capable of burning the widest range of the most wretched coals imaginable; yet the Ignifluid produces "fly carbon" that is extraordinarily coarse. There is a good possibility that dust collection equipment for the Ignifluid, to meet Virginia's standard for example, will be cheap to buy and reliable to operate. The Ignifluid's applicability at ratings as small as 3 to 10 megawatts deserves close study.

Another development opportunity is presented by the "Gas Producer Combustion System" (GPCS) of Livio Dante Porta, practiced in steam railway locomotives in Argentina and South Africa. GPCS appears also to be robust with respect to quality of coal, and there is a possibility that additions of limestone to its static fuel bed can be used to control emissions of sulfur dioxide. Coal-Oriented Advanced Locomotive Systems ("COALS") will use GPCS in its new steam locomotive.

Because both Ignifluid and GPCS systems burn coal in two stages, emissions of nitrogen oxides from both systems will be small.

*** *SULFUR DIOXIDE* ***

What about sulfur dioxide?

This gas, at levels below about 1 part per million, is a mild respiratory irritant and that is all, insofar as human health is concerned. The confusion over putative effects of sulfur dioxide upon human health arose from the fact that it was one of the few pollutants analyzed in the atmospheres of cities during the bad old days of coal smoke. Epidemiologists understood that sulfur dioxide was, for them, merely a "marker" for something else that was bad in the air. They assumed that the something else was related chemically to sulfur dioxide, and most epidemiologists supported clean air legislation focusing on control of this gas.

We have not yet found the "something else."

For a while in the mid-1970s, we all believed that the "something else" was sulfate particulate matter, which curiously persisted in atmospheres of our cities even after sulfur dioxide levels had been cut drastically. We now understand that even sulfate particulate matter has little effect upon mammalian health. What now seems likely is that the epidemiological studies that seemed to establish a connection between sulfur dioxide and health were simply flawed, and that the true connection was with smoke, which tended to get worse or better as levels of sulfur dioxide rose or fell. Epidemiological study in New York City can find no improvement in the New Yorker's health attributable to the reduction since the mid-1960s in the levels of sulfur dioxide that he breathes. It is probable that sulfur dioxide is today well below a level at which an effect upon human health might be detected.

The Environmental Protection Agency no longer speaks of human health in justifying its standards for sulfur dioxide and its drive to bring emissions of this gas under control. The talk now is of acid rain, a phenomenon not related to human health. The talk usually takes place in a context that blames coal combustion for acid rain.

There is no historical evidence of a relationship between acid rain and small-scale combustion of solid fuels when measures are taken to prevent emissions of smoke — i.e., to use smokeless solid fuels or to burn bituminous coals smokelessly. Whatever the relationship may be between acid rain and large coal-fired boilers in electricity-generating stations, there is much circumstantial evidence that the increase in acid rain since about 1950 in both northwest Europe and northeast United States is related to increase in use of oil for heat and transportation.

Indeed, in light of this circumstantial evidence, I believe there is a possibility that small oil furnaces contribute significantly to acid rain. I think there is credible argument that

> *one cost-effective way to reduce the acidity of rainfall in northeast United States might be to replace oil used for space heat and hot water with coal, burned smokelessly.*

It is worth reviewing the evidence on which I base this belief.

First, let us consider Professor Odén's maps of acid rain over northwestern Europe in 1956 and 1966.

> Unfortunately, no comparable maps can be drawn with much confidence for the northeast United States; we simply did not gather the necessary data here.

Figure 2 shows the "explosion" of the acid rain phenomenon in Europe in that decade.

Figure 2

Acidity of Rainfall in Northwest Europe, 1956 and 1966

Explanatory note: pH is an inverse measure of acidity; i.e., the lower the pH, the more acid the rainfall. One unit of pH is equivalent to a ten-fold change in hydrogen-ion content of water.

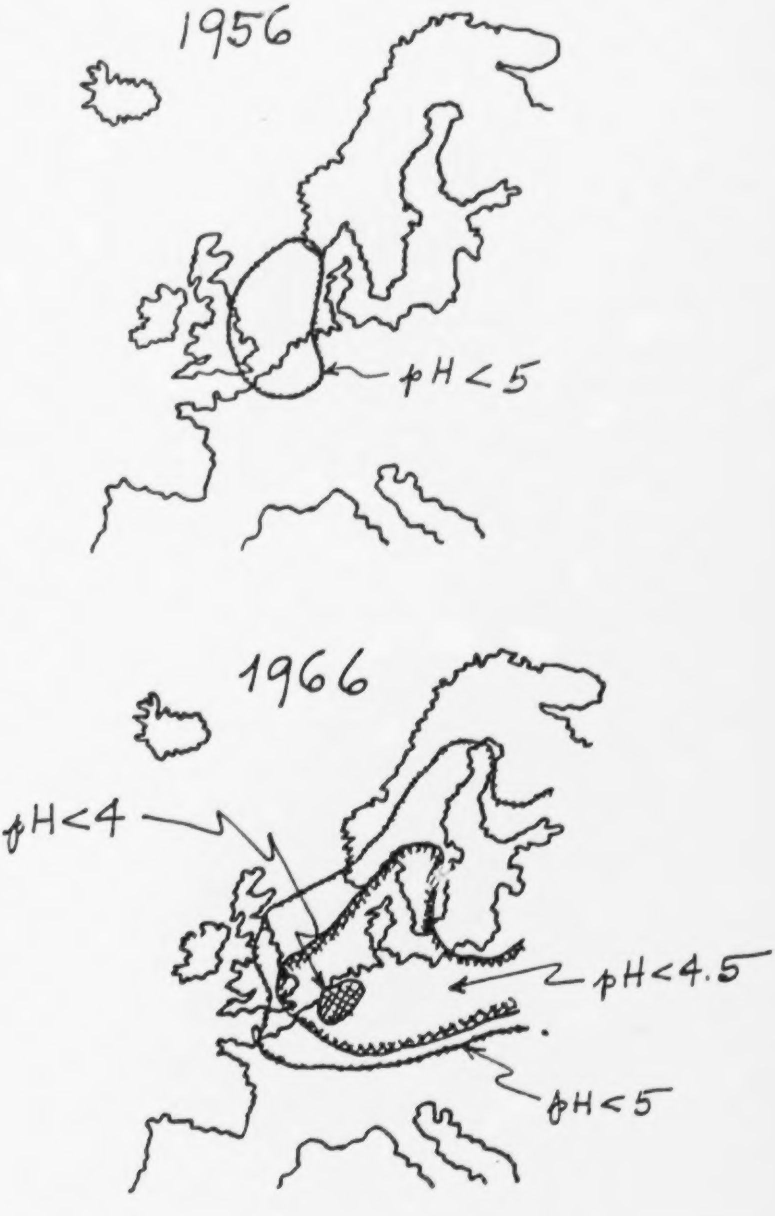


Table 2 illustrates, however, that the decade from 1956 to 1966 was in the middle of the period during which western Europe shifted from coal to oil and gas for growth in its energy supply. Europeans were buying automobiles and trucks in large numbers, and choosing oil for new stationary sources of heat — especially small sources. Consumption of coal remained essentially constant. Since coal for steel and large-scale electricity generation continued to increase, some replacement of coal by oil for heat needs of a smaller scale must have occurred.

Table 2

Annual Consumption of Coal and Oil in Western Europe

(expressed in millions of metric tons of hard coal equivalent)

Year	*Coal*	*Oil*
1950	464	86
1958	540	189
1966	486	516

Ockham's razor

> ("Pluralites non est ponenda sine necessitate" = Multiplicity ought not be posited without necessity)

is a useful principle for the engineer, who must often blend engineering science of limited applicability with imperfectly understood art, in order to make his design and to accomplish his job in the time he is allowed.

Perhaps, then, an engineer will be forgiven if he associates the spread of acid rain in western Europe with this region's shift to oil.

Can we find a reason for this association? I doubt that chemical meteorology is sufficiently mature for us yet to discover a precise, unequivocal reason. But we are pressed to act on the matter of acidity in rainfall, and we cannot wait for a dot-every-eye, cross-every-tee science of acid rain to appear.

Let us ask a narrower question:

Do the circumstances of which we are aware allow us to judge which fuel, oil or coal — burned smokelessly — might contribute more to acidity in rainfall when used in small furnaces to supply space heat and hot water?

I believe that I can answer this question in favor of coal at a probability sufficient to guide public policy. Examination of the question also suggests low-cost research that could lead quickly to a test of my answer and to a large shift in the probability of its being correct. Let me review the circumstances which lead me to my answer:

- Historical evidence of acid rain in the Nineteenth Century seems to be confined to fog-prone districts of northwest Europe where coal was burned with large emissions of smoke.

- Similar conditions — fog, coal smoke, and acidity in rainfall — prevail today in the city of Chongking in southwest China.

- Michael Oppenheimer of the Environmental Defence Fund has recently published an analysis strongly suggesting that three-quarters of the sulfuric acid in rainfall in northeast United States arises from oxidation of sulfur dioxide in water droplets as they form and grow in a rain cloud.

- Soot particles, such as those which coal stoves and small boilers often emitted in the bad old days of coal smoke — and in the People's Republic of China today — are catalytic for oxidation of sulfur dioxide to sulfuric acid in liquid water. In light of Oppenheimer's analysis, accounts of acid rainfall in northwest Europe during the Nineteenth Century and also Chongking's acid rain today have at least one credible explanation: formation of acid in raindrops containing soot particles.

  There are, of course, other catalysts for acid formation in raindrops which may play an important role: e.g., salts of iron, manganese, calcium, copper, vanadium, and nickel. Fly ash from coal combustion almost always contains iron in amounts ample to support the opinion that its salts are significant contributors to acid rain where strict controls on fly ash emissions are not in effect. Whether iron salts or soot particles were the more significant catalysts in the bad old days of coal smoke is not crucial for my argument here; but it would be important to try to discover which is the more significant in the air over Chongking today.

  Nitrogen oxides are also classic catalysts — in the historic lead chamber process — for oxidizing sulfur dioxide to sulfuric acid. Later, I will comment further on their possible role in acid rain.

- Rain in northeast China, however, is alkaline, although both Beijing and Shanghai burn large quantities of coal with large emissions of smoke. The difference between Beijing and Chongking probably arises from two factors: (1) There is far more alkaline dust (principally limestone) in Beijing's air. (2) Chongking is far wetter and more humid — in this respect, much more like cities of northwest Europe — and so sulfur dioxide spends more time in water droplets and has a better chance to become oxidized to sulfuric acid.

- The example of Beijing illustrates that acidity of rainfall in a given region depends in some degree upon the character of the region's rocks.

If they are alkaline, as in northeast China, a large amount of pollution may occur, together with large production of sulfuric acid, before the alkalinity of airborne dust is overwhelmed, and the rainfall turns acid. In this connection, I should note Gene E. Likens believes rainfall in much of the eastern United States before 1930 was alkaline, and of course, limestone is ubiquitous in the East outside of the Adirondacks and New England.

- In regions where rocks are acidic — like Chongking, the Adirondacks, New England, Scandinavia, the Continental Divide in Colorado, and the far Canadian northwest — it takes relatively less pollution to create acid rainfall than in regions where rocks are alkaline.

- Indeed, to what degree must we ascribe the acidity of rain in the District of Mackenzie, in the Canadian northwest, to man-made pollution? Nature makes sulfur and nitrogen oxides, too. Swamps discharge hydrogen sulfide giving rise, through oxidation, to sulfur dioxide in an amount comparable to, but still somewhat greater than man's sulfur dioxide. Lightning creates nitrogen oxides in an amount an order of magnitude greater than man makes with his combustion processes. Whatever the answer may be to my question about the Canadian northwest, acid rainfalls arising from nature's sulfur and nitrogen oxides almost surely occurred in Scandinavia and the Adirondacks long before man appeared. Study of diatoms in sediments of at least one Norwegian lake shows that its acidity has fluctuated around present levels for many centuries, and was at its worst some eight hundred years ago! We are told that fishless lakes have grown in number in recent decades, and this is credible. But no one should suppose that we have it in our power to institute measures which will *eliminate* fishkills in granitic, recently glaciated regions like Scandinavia and the Adirondacks.

- Rainfall in China contains far more sulfate than nitrate. Rainfall in Beijing often has 2.5 to 5 atoms of sulfur (in form of sulfate) per atom of nitrogen (in form of nitrate). Zhao Dian-wu of Academia Sinica's Institute of Environmental Chemistry estimates annual emissions in Beijing, in thousands of tons, as follows:

sulfur dioxide	248.3 from coal	2.0 from oil
nitrogen oxides	11.5 from coal	3.5 from oil

It would be interesting to know how close the nitrate content of Chinese rain comes to that which we should expect simply from presence of lightning-produced nitrogen oxides in China's air.

- A large increase in nitrate content has accompanied the increase in rainfall acidity in northwest Europe and northeast United States, where rain now typically contains only one atom of sulfur per atom of nitrogen.

When rain is acid, two-thirds of the acidity, typically, is due to sulfuric acid, and one-third, to nitric acid.

Emissions in the northeast United States in 1977, in thousands of tons, have been estimated at

sulfur dioxide	29,500
nitrogen oxides	11,500

This works out to be 1.2 atoms of sulfur per atom of nitrogen, about the same as the ratio of these atoms in typical acid rain. This match supports Professor Odén's view, with others, that by far the larger part of the occurrence of sulfur and nitrogen in eastern U. S. and northwest European rainfall comes from man's pollution and not from nature's sulfur and nitrogen oxides.

- William M. Lewis, Jr. and Michael C. Grant of the University of Colorado have published remarkable data for the acidity of rainfall at the Continental Divide in Colorado. In this location, at least, substantially all of the increase in rainfall acidity in recent years can be attributed to increase in nitric acid, and not to sulfuric acid. Rock at the Divide is granite; crustal dust in the air is not alkaline; and, relatively speaking, it takes less pollution to create acid rain.

- Nitrogen oxides are oxidized to nitric acid in the atmosphere, but are themselves oxidants, and are precursors of ozone. If there has been an increase in the percentage of sulfur dioxide oxidized to sulfuric acid in rain clouds which form in polluted air masses in eastern United States and northwest Europe, we do not have to look far to find the increased supply of oxidant!

> This relates of course to my earlier remark about the role of nitrogen oxides in the classic lead chamber process for sulfuric acid. I will return to this point.

- Kenneth Rahn of the University of Rhode Island has attempted to identify regions from which a given polluted air mass came. It is probably never true that a polluted air mass over the Adirondacks, for example, came in its entirety from a particular narrowly defined spot — in the Middle West, for example. In general, Rahn finds that a polluted air mass is a mixture of air from several broadly defined regions. In a series of rainstorms at a given place, the mixture can vary appreciably. For example, rainfall at a given point in New England often reflects a mixture of a lesser amount of air from coal-burning regions of the mid-West with a greater amount of air of nearer origin, where oil is a far more important fuel than coal. On occasion, a New England rainfall arises solely from New England's own air — or at least, from air reflecting little coal pollution — and, so far as I understand Rahn's work, I gather that a rainfall in New England without an appreciable input of pollution from oil combustion would be rare indeed.

> Rahn's method is to look at the composition of particulate matter in air at the time of rain formation, and in New England, he finds non-crustal vanadium which could be present only in soot particles emitted from the burning of oils.

Let us return to our questions:

Can we find reasons for an association between the spread of acid rain and a shift from coal to oil in the 1950s?

More particularly:

Anthracite, a smokeless solid fuel, provided space heat and hot water in northeast United States until the 1950s. Might its replacement by oil have contributed to this region's acid rain problem?

Two points can be made with certainty:

First, the shift from coal to oil was accompanied by dramatic decline in emissions of coal smoke. Even the Nineteenth Century industrialist often tried to do a decent job of burning coal, since smoke represents fuel values worth money that he did not like to waste. Most of the coal smoke in the bad old days of coal came from small stoves and boilers, and these were the units which Europe and the United States abandoned in the 1950s in favor of oil. Nearly every jurisdiction, both in Europe and the United States, insisted that new coal-fired boilers — and many old boilers as well — be fitted with dust collection equipment working at high efficiency.

Second, emissions of soot particles from oil combustion have increased greatly in recent decades. These are far smaller, and have far higher surface area, than anything that emerges from a well-managed coal furnace today. If catalysis of the sulfur dioxide oxidation in raindrops is important, we do not have to look far to find an effective catalyst!

I cannot refrain, also, from a speculation: If vanadium and nickel are present in soot particles from oil combustion, their catalytic power toward oxidation of sulfur dioxide in a raindrop to sulfuric acid is almost surely enhanced.

Soot particles from small oil furnaces in New York City began to contain vanadium and nickel in 1970, when sulfur level required for fuel oil burned in such furnaces was reduced from 1.0% to 0.3%. This was because new low-sulfur oils reached New York from plants desulfurizing residual oils of the Caribbean by catalytic treatment with hydrogen. Is it possible that the New Yorker's health has been hurt more by his having to breathe this carcinogenic soot — and that acid rain in New England was at the same time made worse — than if the sulfur level in oils for New York City had been left at 1.0%?

Be this as it may, soot particles from oil combustion are a new ingredient in polluted air masses from cities and industrial areas of northwest Europe and the United States, added to the air in amounts that have increased enormously in just the past three decades.

Another enormous change in these polluted air masses is the huge increase in nitrogen oxides. I have commented upon their possible role as a "catalyst" for converting sulfur dioxide in water to sulfuric acid — more precisely, as an oxidant in a chemical cycle where its oxidizing power is constantly renewed from oxygen in air. It is of course possible that the increase in nitrogen oxides has greater significance for the acid rain problem than the increase in oil soot particles. This possibility has little effect upon the thrust of my argument. Data on emissions from household furnaces of all types are pathetically few, but such data as exist suggest that emissions of nitrogen oxides from a stove or furnace burning a smokeless solid fuel are significantly below those from a well-managed small oil furnace. It is a reasonable proposition, when viewed from standpoint of emissions of

- nitrogen oxides or

- carcinogenic soot particles laden with vanadium and nickel,

that New York City's atmosphere could be bettered by a return to its historic fuel -- anthracite -- or to smokeless solid fuels manufactured from low-sulfur bituminous coals.

> For those who, like me, remember the hazard of getting a large grit particle in one's eye during a stroll on a windy day in New York City around 1950, I should mention that the particle probably came from a tug in the harbor burning bituminous coal at high intensity, not from a neighborhood anthracite furnace.

Unfortunately, little work has been done on emissions from small oil furnaces at sizes ranging from the furnace for an individual home to the furnace heating a typical apartment building in New York City. I lived in New York City for several decades, and my observations there suggest to me that, in general, the smaller the furnace the larger the quantity of soot it produces per barrel of oil consumed. Owners of small apartment buildings, in particular, tend to neglect maintenance and to entrust operations of their furnaces to unskilled personnel. A subjective observation is that something like one oil furnace out of twenty is managed by an operator who daily puts out dense clouds of black soot for several fifteen-minute intervals, in summer as well as winter. No doubt it would be difficult to develop a good figure for emissions of soot from oil combustion in New York City, but an effort should be made, with measurements from furnaces representing a wide spectrum of age, type, history, and conditions of maintenance and operation.

The immediate environs of New York City appear to have rainfall of as high acidity as any part of the Nation — higher, indeed, than downwind New England. Is New York a major source of rainfall acidity?

An experiment worth performing would be to conduct emissions from an oil-fired appliance into a chamber with controlled temperature, humidity, and radiation, and to create a fog of water droplets in the chamber. The appliance should be run properly in some tests, and in others, badly, to produce large amounts of soot. Work on coal appliances should parallel the work on oil, using both good and bad coal appliances — i.e., ones that burn bituminous coal smokelessly and others that emit smoke. There should also be tests of devices burning smokeless solid fuels — cokes and anthracites. I would expect to see higher conversion of sulfur dioxide to acid in the emissions containing smoke, and highest of all in a badly run appliance burning an oil like that now used in New York City — i.e., containing vanadium and nickel.

Let me emphasize again that I am arguing a narrow point:

> *I believe that a shift from oil to coal for small heat needs may help our nation's acid rain problem.*

Whatever should be done about sulfur dioxide emissions from large electricity stations, it would be difficult to argue that a small increase in emissions of this gas from household and commercial furnaces for space heat, accompanied by decrease in emissions of oil soot and nitrogen oxides, will make acid rain worse.

It would also be difficult to advance an argument based upon human health against relaxing our Nation's current sulfur dioxide emission standard for small appliances in order to facilitate pilot projects to convert selected sets of users from oil to coal, especially if selections are limited to rural or small-city settings. Relaxing the standard by a factor of 2 would make it far easier to provide the projects with suitable coals in our Middle West, and could be helpful in the East. The best applications for early conversion to coal are probably to be found on farms — for example, to warm baby chicks or hogs, to cure tobacco, to dry grass or alfalfa, or to process dairy products. Projects can be monitored for effects upon the environment that could not possibly have widespread implications for harm before they were discovered.

Programs for Backing Out Oil Used for Space Heat and Hot Water

What can we say about programs to back out 250,000 barrels per day of oil for domestic space heat and hot water and another like amount used for these needs in agriculture, commerce, and industry?

Efforts to meet these targets will face problems associated with combustion of the wide range of coal types available in different parts of our nation, as well as the widely differing types of appliances or furnaces suitable for burning the various coals with acceptable emissions of pollutants and economy of operation.

Selected Land Grant Universities should execute programs to promote coal in their regions, each operating a program which focuses on its region's coals and heat needs. Each center will need to mount research in small-scale coal combustion and to develop an advisory service to train operators and disseminate knowledge of good practice to owners, manufacturers, and installer/maintainers of boilers and furnaces. The work of developing advisory services will be speeded if a center executes pilot projects to introduce coal combustion to selected sets of users, such as chicken farmers, most of whom now use propane for space heat.

> I cannot resist commenting that DOE has proposed no synthetic propane plants! Yet maintaining chicken flesh as the meat bargain in supermarkets and making this food supply more robust against another oil crisis are surely objectives which our nation's consumers will understand.

Work of regional centers will parallel closely other activities now undertaken by Land Grant Universities together with their Extension Divisions. Over the years, a special relationship of trust has developed between State Extension Services and farm communities. Nearly every rural County has its farmer of pioneering spirit, eager to try out a new procedure when his County Agent offers evidence that it can lower his costs. The ongoing collaboration between Extension Services and agriculturalists can be a positive factor toward success of early projects reviving small-scale coal combustion.

Influence of programs executed by selected Land Grant Universities will quickly extend beyond the boundaries of their states. Extension Divisions of these universities constitute an information network blanketing our nation. All extension services watch each other's activities, and quickly apply advances that will help their states. Washington has a tendency to meet new problems with new federal institutional arrangements. For small-scale coal combustion, what is needed is *NOT* a new federal information service, but a sensible application of state institutions already in place and in close touch with state needs and moulders of state opinion.

Studies at the centers will take us out of our cultural isolation in respect to coal combustion and related matters. Early steps to be taken, in planning work at the centers, are

- visits to laboratories for small-scale coal combustion research and coal advisory services in support of such combustion in Great Britain, New Zealand, Denmark, and Norway;

- visits to manufacturers and users of coal appliances and boilers that depend upon these laboratories and advisory services;

- visits in these countries to environmental control authorities that concern themselves with small-scale coal combustion;

- visits to plants manufacturing smokeless solid fuels in England and on the Continent;

- visits to a site for mining of brown coal in West Germany by the "moving hole" concept, that is applicable to mining anthracite from the Mammoth Seam of northeast Pennsylvania;

- visit to a coke oven in Japan along with environmental authorities;

- visit to Beijing, People's Republic of China, during Winter, to see what coal smoke was like in the bad old days of coal;

- atmospheric chemistry studies and epidemiological studies in Beijing and Chongking, China, in Dhanbad, India, and in other places in the World where coal smoke can still be found in abundance:

  — to get data on polycyclic organic matter (POMs), polycyclic aromatic hydrocarbons (PAHs), and trace elements which no one knew how to measure in the bad old days of coal smoke; and

— to try to establish whatever connections there may be between these "new pollutants" and human health;

- studies of acid rain in China, where coal is still the principal fuel, and contrasting studies in South Africa, where small-scale coal appliances are largely confined to black townships, and large-scale thermal electricity from coal is more advanced than in China.

I have suggested pilot projects to convert selected sets of users to coal. Users who particate in a project need to be protected against two possibilities: that environmental monitoring will reveal unsuspected adverse effects requiring serious modification or re-selection of a furnace for the project; or that the furnace selected is a lemon and must be discarded. Low-cost insurance provided by the federal government could answer to these risks. Certification of a furnace as insurable would be a signal to everyone that it has passed tests for both emissions and economy. As confidence builds, insurance of furnaces could move to the private sector.

A special problem for a pilot project will be securing a reliable supply of coal of the quality needed for the furnace selected. Small users of coal lack means for analyzing the coals they buy. Small coal miners also often lack such means, or lack the will. A distributor able to exercise control of the quality of the coals he sells, ideally, should stand between the coal miner and the small user.

The problem is different for "domestic solid fuels" for homes and "commercial coals" for commercial and small industrial users.

For the first, I believe the easiest path of development in the United States, at least in the near future, will be to create supplies of smokeless solid fuels. To develop smoke eaters that we could be *certain* will give satisfactory performance in hands of householders, and at the same time to develop supplies of the special bituminous coals our smoke eaters will require, will take too long.

For "commercial coals," grades of coal of suitable quality now exist and are available to large-scale industrial customers. The question is, who will undertake to distribute the coals at a smaller, commercial scale? British Petroleum and Shell will market quality-controlled coals to small users in Denmark, and Norcem, the Norwegian cement company, will sell coal in Norway. Until a company here recognizes this commercial opportunity, pilot projects operated by regional centers, perhaps with help from farm cooperatives, may need governmental help in assuring supplies of suitable coals.

> There are more than 100 greenhouse establishments in Denmark and Sweden using coal heat, primarily from underfeed stokers. Norcem has found its first enthusiastic pioneers for small coal furnaces in Norway's lettuce- and cucumber-growing greenhouse industry. Norwegian farmers are much concerned with labor costs. Osmund Espedal of Lier, near Oslo, owns an establishment with 52,000 square meters under glass, and has contributed ideas to the design

> of solid-handling equipment and control devices for his new 4.6 megawatt chaingrate stoker which permit him to operate his heating plant without attention over a weekend, and with only one or two man-hours of labor in the daytime during the work week. Yet his plant cost a remarkably low 543.5 Norwegian kroner per kilowatt (ca. $76). His furnace house can accommodate a second stoker, which would cost ca. $28 per kilowatt, providing him with 9.2 megawatts at a total outlay of ca. $52 per kilowatt.
>
> I am sure there are American farmers with skills and imaginations equal to Espedal's, who could contribute to development of modern heat plant to meet agricultural needs.

I propose that two activities related to small-scale coal combustion be made subjects for experiments in environmental control. I do this because I regard re-establishment of supplies of smokeless solid fuels in the United States as an urgent matter. Both our anthracite mining industry and our coke-manufacturing industry are in deep disarray. They are poorly prepared to expand, and a major reason for this — not the entire reason, of course — is the cumbersome, slow, and unsympathetic bureaucracy with which they must deal to get clearances on environmental matters.

The experiments in control would be to set up offices to watch these industries modelled upon the office of the Chief Alkali Inspector in Great Britain. This office is staffed by a remarkably small number of people who are expert in what constitutes "sound practice" for the economic activities which they regulate. Control decisions involve dialog between experts and are based upon individual cases. This is in sharp contrast to the large number of governmental participants here — scattered through many agencies, in poor communication with one another, often poorly informed about technological issues affecting the cases they must deal with — who have little choice save to treat each case "by the book."

The risk that these experiments in control would lead to environmental insults of concern is miniscule in comparison to the danger that people will suffer because they cannot afford to heat their homes adequately if cheap coal heat is not provided. It is miniscule in comparison to the odds that our Nation will face yet once again an overnight drop in availability of oil.

Increasing the resiliency of our response to another oil crisis is not the only reason these matters are urgent. Scores of coal stoves are being offered on the United States market today that are not capable of burning bituminous coal without copious emissions of smoke. Economic motives to use coal to supplement oil or electric heat are strong. No "book" got written for regulating small wood stoves, and equally strong economic motives have already produced atmospheres polluted with wood smoke in northern and western cities and villages. No one is paying attention to control of small coal furnaces either. If we delay, a rush to buy unsuitable equipment could re-create the bad old days of coal smoke, confirming uninformed prejudice, and delaying a responsible revival of coal heat.

APPENDIX: Costs of Small Coal Furnaces for Space Heat and Hot Water

This Appendix gives cost figures from which I have abstracted those given in Part II above.

In reckoning replacement of oil by coal, I have used the following thermal efficiencies:

Residential coal furnace	54%
Residential oil furnace	59%
Commercial or small-industrial furnace, coal	70%
Commercial or small-industrial furnace, oil	76%

I have taken these efficiencies from E. N. Cart, Jr., M .H. Farmer, C. E. Jahnig, M. Lieberman, F. M. Spooner, *Evaluation of the Feasibility for Widespread Introduction of Coal into Residential and Commercial Sectors*, report from Exxon Research and Engineering Company to Council on Environmental Quality, April (Part II) and August (Part I) 1977. This report's conclusions are no longer valid because oil prices have tripled in the meantime, and its authors failed to note the sensitivity of their findings to the price of oil. The report is still valuable, however, for its review of oil-heating appliances now in place, candidates for replacement by new coal furnaces.

In any case, my "impressionistic picture" of the economics of coal heat does not much depend upon exact values of efficiencies. I am aware that modern domestic oil furnaces, for example, can achieve higher efficiencies than the 59% value given by Cart *et al.*, but so also could modern coal furnaces; and, if anything, the efficiencies I am using understate the incentive to replace an old oil furnace by a modern coal device.

Domestic furnaces

A simple, coal furnace heating air at ca. 10 kilowatts output might cost in the neighborhood of $40 per kilowatt. Payout times for an owner who burns a smokeless solid fuel at $120 per ton would be:

Number of hours per year during which heat is needed at full output of furnace	1,000	2,000
replacing oil at $1/gallon	3.3 years	1.65 years
replacing oil at $1.20/gallon	2.0	1.0
replacing oil at $1.40/gallon	1.4	0.7

Payout times are shorter in proportion to greater number of hours per year during which heat is needed. It is worth noting that a small furnace used to furnish supplemental heat will operate more hours, other things being equal, than a larger furnace used to heat an entire house.

For an owner who burns bituminous coal at $80 per ton in a simple, hand-fired furnace at ca. 10 kilowatts — *probably emitting smoke!* — payout times would be:

Number of hours per year during which heat is needed at full output of furnace	1,000	2,000
replacing oil at $l/gallon	1.7 years	0.85 years
replacing oil at $l.20/gallon	1.3	0.65
replacing oil at $1.40/gallon	1.00	0.5

A small, sophisticated coal furnace burning bituminous coal smokelessly and heating air or water at ca. 10 kilowatts heat output, with hand firing and ash removal, might cost about $100 per kilowatt. Payout times with bituminous coal at $80 per ton would be:

Number of hours per year during which heat is needed at full output of furnace	1,000	2,000
replacing oil at $1/gallon	4.3 years	2.15 years
replacing oil at $1.20/gallon	3.2	1.6
replacing oil at $1.40/gallon	2.5	2.25

A domestic furnace burning bituminous coal smokelessly and with automatic coal feed following heat demand, at ca. 40 kilowatts heat output might cost ca. $80 per kilowatt. Payout times with bituminous coal at $80 per ton would be:

Number of hours per year during which heat is needed at full output of furnace	1,000	2,000
replacing oil at $1.00/gallon	3.4 years	1.7 years
replacing oil at $l.20/gallon	2.5	1.25
replacing oil at $1.40/gallon	2.0	1.0

Commercial, agricultural, and small industrial furnaces:

Costs for installations of underfeed stokers, including fabric filters for dust collection, might run, at several commercial sizes:

Rated output, kilowatts	900	1,500	4,500
Capital cost, per kilowatt	$62	$42	$28
At a coal cost of $50 per ton and an oil cost of $0.80 per gallon, for operation at full output during 1,000 hours per year:			
Payout time, years	3.73	2.52	1.68
At an oil cost of $1.00 per gallon:			
Payout time, years	2.68	1.81	1.21

Chaingrate stokers tend to require less labor than underfeed stokers, but their cost, including fabric filters, is greater:

Rated output, kilowatts	4,500	9,000
Capital cost, per kilowatt	$86	$62
At a coal cost of $40 per ton and an oil cost of $0.80 per gallon, for operation at full output during 1,000 hours per year:		
Payout time, years	4.65	3.35
At an oil cost of $1.00 per gallon:		
Payout time, years	3.44	2.48

Recent U. S. installations of both conventional and fluidized-bed combustion boilers raising steam at ratings of ca. 5 to 20 megawatts have cost about $100 to $150 per kilowatt. Readers familiar with these units may be surprised, as I was, by the lower costs which I found in Norway for plant which simply heats water. My costs may reflect the simpler equipment needed for heating water versus raising steam, and perhaps also ingenuity on the part of the Norwegian greenhouse operators who cooperated with Norcem engineers in laying out the heat plants which I saw.

Many jurisdictions would require continuous attention of a steam boiler by a skilled operator at heat ratings well below outputs at which they would permit unattended operation of water heaters.

Capital Costs for Equipment to Back Out Oil

The capital costs which I have given above can be translated into costs for environmentally benign equipment to back out one barrel per day of oil (annual average) now used for space heat and hot water —

— *in households:*

Fuel	Smokeless Solid Fuel	Bituminous	Bituminous
Furnace	Hand-fired	Automatic	Hand-fired smoke eater
Installed cost, $/kw	$40	$80	$100
Rating, kilowatts	10	40	10

Capital to back out 1 barrel per day of oil (annual average) if heat is delivered at full rating of appliance for

1,000 hours per year	$25,200	$31,300	$38,600
2,000 hours per year	$16,700	$16,600	$20,300
4,000 hours per year	$12,500	$ 9,300	$11,200

— *in agriculture, commerce, or industry:*

Installed cost, $/kw	$28	$42	$62	$86
Underfeed stoker, rating, kilowatts	4,500	1,500	900	—
Chaingrate stoker, rating, kilowatts	—	—	9,000	4,500

Capital to back out 1 barrel per day of oil (annual average) if heat is delivered at full rating of furnace for

1,000 hours per year	$15,200	$21,800	$31,200	$42,600
2,000 hours per year	$ 8,600	$11,900	$16,600	$22,300
4,000 hours per year	$ 5,300	$ 6,950	$ 9,300	$12,100

These capital costs include either $2,000 for a new bituminous coal mine or $8,200 for a new supply of smokeless solid fuel respectively. If there is excess bituminous coal production capacity, to supply either raw coal or feedstock for manufacture of smokeless solid fuel, the capital costs are of course less by $2,000.

Senator **Warner**. Well, we thank you very much, Dr. Squires. You speak with a great deal of conviction and enthusiasm. I would like to come by and see how you are heating your home.

STATEMENT OF DR. RICHARD A. WOLFE, VICE PRESIDENT, RESEARCH AND DEVELOPMENT, UNITED COAL CO.

Dr. **Wolfe**. Thank you for this opportunity to come back to my old alma mater, Virginia Tech, and make a presentation representing a coal company's viewpoint with regard to what are the problems with the coal industry and what can we do about solving some of these problems, both the short term and the long term. I noticed when I was walking around as a senior in chemical engineering, that I was the only student 22 years ago working with coal and coal conversion to liquid fuel. I am pleased to see a professional like Dr. Squires here who has been very much a formidable supporter of coal and new technologies for coal in the Chemical Engineering Department. I believe now, as I did then, that coal is our greatest national resource and we have just begun to develop its uses. Primarily, in this country, there have been two uses for coal. We have only used it for steel and for burning in utilities. The steel market, as you have heard already, is starting to dwindle and the utility market always had competition with oil and natural gas, nuclear, and hydroelectric. So we, in the coal industry, must take some steps now. These steps should have been taken 20 years ago. But now is the time to start a beginning. We can't wait 5 more years and look back and say we should have started 5 years ago. I think it's time now that we as a government, we as an industry, and we as a user, and including the railroads, start to reunite together to develop some strategies in which we can convert coal to the uses that we can use to replace imported oil. Senator, as I know you are well aware of the demands for energy in this country, the largest, biggest threat we have today from a national security standpoint and a threat to the coal industry itself is imported oil. We are still importing 3 to 4 million barrels every day of oil and it is something like $100 million every day that is going out of this country for imported oil. I don't mind using the mideastern oil, I just hate to pay the high prices for this oil, that's going out of our country. Much of this oil has replaced, in the past, coal markets that existed. A good example is a home heating fuel, as Dr. Squires has already mentioned. Another example is locomotive engines. Locomotives, not too many years ago—10 or 15 years ago—were working primarily off steam engines. They were using coal. They were hauling coal hired by coal. Today they are using diesel fuel. One major railroad told me last year they alone spent over $500 million for diesel fuel. That equates to 4 or 5 million additional tons of coal. I think it's time that we, as an industry, started directing ourselves to get back some of these markets that we have lost to oil. And I think we can. The technology is here, we need to further develop it, but we need to have the support of all those people who are making their living off coal. We need the support of the utilities. We need to have regulations so that the utilities can sponsor additional research in coal. They are the big users of coal. We need to have railroads who are big users and big suppliers in making that transport of coal. Putting money back into our end. We need the coal industry to be viable.

Senator **Warner**. Could I interject at that point? I have been acquainted for many many years with Ross Rowland, whose name was mentioned earlier. Ross is the man that had the vision and foresight to finance and run the Feedom Train throughout the Bicentennial. I got to know him then insofar as that was possible. People said he could not make the Freedom Train run but he made it happen and it was a very successful exhibit and, of course, it ran by steam throughout America. I have watched with interest Mr. Rowland's development of his coal-fired locomotive, as a matter of fact I sat down and looked at the young engineer with his technical drawings and based on my hazy recollection of fundamentals, I think it might work. But my question to you is, Are there other R&D think tanks working on restoring to the rails a coal-fired locomotive?

Dr. **Wolfe**. Yes; one other company is doing some work in that area, as well.

Senator **Warner**. Is it feasible?

Dr. **Wolfe**. It is indeed. Let me just mention that I think its going to take some support from the Government and from industry as well, but I don't see—and I'm realistic—that you can convert coal into such a liquid form that you could possibly still convert it into the diesel engines that are being used today without major retrofit. So those technologies are on the horizon, Senator.

Senator **Warner**. Utilizing the present rolling stock, the engines, and putting some modest conversion factor into their train of combustion to accommodate liquidized coal?

Dr. **Wolfe**. That's right. I think the biggest future use, besides what Mr. Blackmore mentioned earlier, is regenerating coal into today's marketing utilities by burning coal instead of oil. That is, developing coal into liquid form. This will provide all those avenues that has made the oil convenient because of its liquid form. Diesel, for example, today—we are used to paying high prices for fuel—diesel today at $1 a gallon equates to about $7 a million Btu. Coal at $30 a ton or $40 equates to $1.50 a million Btu. So we have plenty of room to upgrade coal to a liquid form and still be competitive. But we've got to have some Federal support.

Senator **Warner**. Well now, let's just take that point. You are talking to the supplier of the currency here. Is my Department of Energy man still with us? Because I've handled part of the research and development on that subcommittee but I don't recall this year anybody coming forward and asking for any money in connection with the rail systems or anything like that. Could you help me on that? Was it asked for? Is it being done? If not, let's get it in next year's budget.

Dr. **Wolfe**. Well, I'm working real close with the Department of Energy now and Don Bauer on some projects that they will support the development of this form of coal.

Senator **Warner**. In the coming 1984 budget?

Dr. **Wolfe**. Yes, in the coming 1984 budget. So we are, indeed, starting a small program with the Department of Energy support.

Senator **Warner**. You are working closely—when you want the money, you come to see me and I will work to get the money. It's as simple as that.

Dr. **Wolfe**. That's the kind of support we need to have in Washington. But I do think, Senator, that it's going to take more than what the Federal budget is for coal R&D. One of the large disappointments to me is that we have initiated a Synfuel project here in this valley, right near Radford, 3 years ago. You were a big supporter of that, as you remember. It's a big disappointment to me to know that 3 years later we still don't have that plant, they don't even have the ground broken. I think we need to have support from Washington again for synthetic fuels because that's going to open up a vast amount of new coal demands and if you can just think and recollect what that plant would have done for this region, the thousands of jobs it would have created and the demand for 3 to 5 million tons of coal. So I think we need to reinitiate this emphasis on sythetic fuels as well as converting coal to liquid form. And we, certainly in the coal industry, appreciate any support that you can give us from Washington. We appreciate the support of the users, helping us in this area of research to develop liquid coal. Thank you.

[The prepared statement of Dr. Wolfe follows:]

PREPARED STATEMENT OF DR. RICHARD A. WOLFE

Mr. Chairman and distinguished visitors and participants, I am Dick Wolfe, Vice President of Research and Development with United Coal Company. It is my pleasure to have this opportunity to participate in this hearing. God knows, we should have initiated such hearings 10 years ago.

Your subcommittee is in its initial phase of hearings and you have already heard from many different people with many different perspectives. And I want to give you yet another perspective. A perspective you have not yet heard and one that will hopefully make a lasting impact on the direction of increased coal utilization, new markets, and federally sponsored coal research and development.

This perspective comes from being the son of a West Virginia coal miner and one whose father died from Black Lung disease; a perspective from one raised and reared in the coalfields near Sophia, West Virginia (which, by the way, is also the hometown of U. S. Senator Robert C. Byrd), a perspective from one who was employed in the U. S. nuclear weapons and space programs for 13 years, a perspective from one who worked as a federal employee for 5 years in Washington, D. C. with the Atomic Energy Commission, the U. S. Energy Research and Development Administration and the Department of Energy; a perspective from a member of the Virginia Coal & Energy Commission and a perspective from one now directing the Research and Development Department of the largest privately owned coal company in the United States.

My objective here today is to give you specifics about the good and bad of the current coal industry and where additional emphasis should be placed in order to improve future coal markets.

Current Coal Industry

The primary problems facing today's coal industry are the same as those that have faced the industry for the past 50 years; too much coal supply and not enough demand which relates to a limited coal market. The steel and utility industries have always been the primary coal users and now we find the steel markets dwindling and being replaced by plastic and other new synthetic materials. The utility market continues to have competition from hydroelectric, nuclear, oil, natural gas, and in the future, solar. We as a coal industry can no longer sit idly by and wait for these "ole faithful" industries to return to great usages of coal. We as an industry, working hand-in-hand with the federal government, need to develop new and expanded markets for coal. These markets exist today - we only need to develop the coal technology to meet these new markets.

Three major new markets exist which could utilize all the excess coal we can produce as a nation:

1. Converting coal to gasoline for automobiles.
2. Converting coal to diesel fuel for locomotive engines.
3. Converting coal to a liquid fuel form to replace oil in utility and industrial boilers.

If you will notice, all three of these new markets are currently being satisfied by oil, most of which is imported.

Development of these new coal markets will benefit this nation as a whole by reducing our dependency on imported oil. Now that we do not have long lines at the gas pumps, let's not ever forget that this country's villain is "imported oil." Energy is still the big issue, even if it is no longer the most popular. I believe that solving our country's energy problems would take care of just about all the other problems such as unemployment, national deficit, high interest rates and national defense.

For example, the United States spent over $40 billion last year for imported oil. This money left our economy; very little returned and it continues to drain our economy daily like a ruptured artery. The multiple factor of the money exported for imported oil, if it were circulated within our own country, is worth about $280 billion. You tell me, would not circulating this money back into our economy put Americans back to work and eliminate any national budget deficit?

We now have the highest unemployment in the coalfields in over 30 years. Ironically, this is the time when we should be developing our own national coal resources at "full steam" to replace this villain called "Imported Oil." It is almost criminal to think that we are importing 3-4 million barrels of oil daily while millions of tons of coal are stockpiled and thousands of coal miners are out of work.

One thing is certain, it is time that this country stopped playing politics with our national energy needs and programs. No matter how many jet planes, new ships, or other sophisticated defense projects we build, if we don't have fuel to run them which is captive to our own national resources, we will not have a strong national defense. Our nation, and for that matter, any nation, is just as strong militarily as its energy resources necessary to run that war machinery. Our national threat is not from the Soviets; it is from what Abraham Lincoln once described as our own internal national weakness.

Technology Needed to Develop New Coal Markets

United Coal Company is one of the coal industry's biggest advocates of research and development for new coal markets. During the past 4 years, we initiated a major project to build a major coal-to-gasoline plant in nearby Radford, have already converted and tested over 500 tons of Virginia coal into a coal-water mixture "liquid coal fuel" form, and modified a commercial coal preparation plant to produce a superclean coal with less than 2 percent ash and 1 percent sulfur. Even with all the new and exciting coal developments sponsored by United Coal Company, the technology needs more resources than those that can be provided by our small company.

Let me say at the outset that the coal industry needs the support of the federal government's research dollars. It is in the best interest of the nation and the coal industry to develop our own coal industry's technologies to replace imported oil. Over the years, federally funded research in the nuclear, military, and aerospace arenas have contributed tremendously to the advanced state of these industries. The coal industry has never received the kind of technology development support that these other industries have received. All the fault cannot be placed on government; the coal industry is also at fault for not supporting to a greater extent their own research and new market development. However, United Coal Company is hopefully setting the example for the industry in establishing one of the premier research and development organizations.

It should be made clear that both the coal industry and government need to redirect themselves to increased coal technology development. Let me also say that the coal industry includes not just coal companies but also the railroads, who make most of their money transporting coal, and the utilities. Through EPRI (Electric Power Research Institute) the utilities are already doing a great deal of R & D but the railroads have little, if any, sponsored R & D which is directed towards increased coal use.

After being a federal employee in Washington and witnessing firsthand the waste of taxpayers' dollars on misdirected programs, I totally agree with the need to drastically cut federal spending. This opinion applies as well to the Department of Energy's programs. The DOE, as initially conceived, started projects on all phases of energy-related activities without a clear direction on priorities and needs. With the drastic cutbacks in federal dollars, it is now more important than ever that the federal dollar be spent wisely to achieve the maximum objective.

But, profoundly and just as strongly as I can say it, I believe the federal DOE funded coal budget should be substantially increased beyond current levels. What has been most disturbing to me in the Department of Energy's budget for 1982, 1983 and that contemplated for 1984 is that there has not been a unilateral cutback in the various energy programs but rather a build-up in the nuclear R & D programs at the expense of coal and other alternative energy programs. Gentlemen, this misalignment of federal DOE funds is blotted with politics. The coal program cannot and should not be just a Democratic Party program and the nuclear program a Republican Party program. God knows, we need them both if we are to defeat the "Imported Oil Villain." It doesn't make sense to reduce the coal R & D program by more than 50% and increase the nuclear program by more than 50%.

Where are our national energy priorities? Much of the nuclear funding is hidden deep within the budget under defense programs so one doesn't even know how much nuclear R & D is really funded. The $3.5 billion Clinch River breeder reactor is just one of the more visible nuclear projects that should not be funded at this period of tight federal spending. A much better alternative would be to build a federally sponsored coal-to-gasoline plant to demonstrate the technology and to reduce this importation of oil that is financially draining our economy. We must recognize our national security and economic threat comes from imported oil and, therefore, structure our federal R & D funds towards eliminating that single most damaging albatross.

Thank you for this opportunity to present my analysis of the federal energy budget. As national leaders, you must find a way to set a course to obtain national energy independence. The course is long and will, undoubtedly, span several Administrations with different political bias. However, we must stay on course if this nation is to achieve our energy objectives or we will truly repeat Roman history of "fiddling while Rome burns."

Senator **Warner**. The Synthetic Fuel Corp. has let us know that they're going to resolicit on these projects. They're in the process right now. Thank you very much, Mr. Wolfe, it's been a pleasure to have you.

Now, I am quite excited over our next witness simply because a month before last he came to the Congress and testified on the new projects his company is doing in the defense area. His company has built rocket engines and fuel—mostly the fuel for many of he Navy's missiles. And now it's put that same resource and brainpower to work on coal and I think he has some exiciting comments to make.

STATEMENT OF CHARLES B. HENDERSON, SENIOR VICE PRESIDENT, ATLANTIC RESEARCH CORP.

Mr. **Henderson**. Thank you, Senator. It is certainly a privilege to be here this morning and talk before you, a friend of our company for so many years. I want to talk about two programs today of Atlantic Research Corp. both of which I feel should have a big impact on the use of coal, not only in the United States but abroad.

One of these is the development of coal-water mixtures as a low cost liquid fuel and this product is really very close to commercialization. The second program, the removal of organic sulfur from coal microbiologically is just beginning to emerge from the laboratory. We began our program in coal-water mixtures, which I spend most of my time on, about 6 years ago, with small programs with the Department of Energy and the Electric Power Research Institute, but well over 90 percent of the funds has been from our own corporate funds. We have given the name ARC-COA1 to number of combustible mixtures of pulverized coal, water and certain additives. Typically the mixture has 70 to 72 percent coal moisture-free basis with 29 percent water added total and 1 percent or less of additives which are used in small quantities to get the right consistency and prevent sediment. These fuels have been developed as a replacement fuel for exisiting boilers, retrofit fuel for existing boilers, both utility and industrial and also in furnaces, electric furnaces.

Coal-water mixtures have a number of advantages which I will go over rapidly. First of all, I should mention the fact that we have a liquid fuel; that's very important to transportation, storage, pumping, pipeline flow, injection, and furnaces. The utility of having a liquid is very marked and chemical plants refuse to have anything to do with solid fuel. Its low cost per unit of energy. That's absolutely essential if we are going to sell this new product. We must have a fuel at lower cost than oil. I will talk a little bit more about that.

Senator **Warner**. Could you use the ratios that Dr. Wolfe provided of roughly $7 per unit Btu for the oil vice $1.50 or the coal?

Mr. **Henderson**. For the coal, $1.50, and we assume that by the time the coal gets to our processing plant by rail it will have added to the cost and it will be $2 to $2.20 per million Btu's. In large scale production we're going to add about .70 per million Btu's when we convert it to a liquid form and so we're talking about $2.90 perhaps f.o.b. our processing plant which means that we should add some more transportation and distribution costs, but you're still only something about $3.20 per million Btu. And that's considerably less than even the No. 6 price of oil which averages about $4.50 per million Btu.

Senator **Warner**. Let me get that $4.50 breakdown.

Mr. **Henderson**. For diesel fuel No. 2, $7; $4.50 is for No. 6 oil which is where we see our initial very large market to replace No. 6 oil at the present time.

These coal-water mixtures have other advantages. They are available now; we're ready to build a commercial plant as soon as we can establish a market. We're independent of all foreign raw materials. We can integate our process with coal cleaning. We've heard how important that is this morning. We can integrate with coal-water slurry pipelines, a topic of interest in Virginia lately. We use only a small amount of capital for a processing plant compared to syn fuel plants.

I've mentioned economics so I'll go on to the market for coal-water slurries. Approximately 2 million barrels per day of No. 6 oil is used both for utilities and industry. Utilities uses approximately 50 percent of this market and industry the other 50 percent. I see both of these as important parts of our market, as well as a third part, namely, the foreign market. The foreign market is of interest. We feel that coal-water mixtures will be made abroad, using western technology, hopefully, although there is Swedish technology. We also see the potential of producing coal-water mixtures in the United States and shipping it abroad as a coal-water mixture. Some people say you're crazy, nobody is going to pay to ship across the Atlantic or Pacific Ocean. But when you look at the capital costs of loading and unloading solid coal versus the capital costs of pumping a mixture onto a tanker, of which there are many in mothballs, you can pay for a fair amount of water to be shipped across the ocean. It doesn't have to be shipped as a 30 percent, 20 or 25, you can ship that across and save considerably on the shipping costs. So we see the export market in this field as being important.

What coal types can we use? Most of our work has been done with Appalachian coals, bituminous coals, and there are really very few restrictions on what kinds of coal we can use to make slurries. I would prefer for it not to be too hard so the electrical costs for grinding are not so great and the inherent moisture content should not be too large. Really, almost all eastern Appalachian coals can be made into coal-water mixtures. In addition, we've also done some work with western coals and made slurries from a semibituminous comparable coal from southern California. The properties of the fuel—important properties—are its got to be fluid. You've got to be able to pump it, you've got to be able to pour it, and be able to atomize it in the boiler and what have you. So its got to be a very fluid material. An ordinary mixture of 70-percent coal and 30-percent water is really a lump of wet sand, at best. But by putting some technology into it—which is actually an outgrowth of our military slurry field technology—by adding additives, by grinding this the right way, you can get very very liquid fuel. Stability is another important property. It must last for a considerable period of time without the coal settling out. The thermodynamic properties of the fuel are very close to those of oil in terms of Btu's per cubic foot of stack gas which is an important parameter, as well as flame temperature. The flame temperatures are a little bit lower so we can expect a little bit less of NO_x.

COMBUSTION PROPERTIES

We started to burn this fuel in our Alexander fuel testing facility in October 1979. We found that with proper burner design we could get good stable flames that were very similar to oil flames. Since that time, combustion tests have been done not only in this country but all over the world. We have shipped the material to Japan, France, England, and Holland and combustion tests have been done very successfully. We have two pilot plants which we have built to manufacture this fuel. One, a small one, 100 gallons per hour which has been in operation since January 1980. The second plant, which we built in New Post, outside of Fredericksburg in Spotsylvania County, is rated at 25,000 gallons per day and in that one we started to produce fuel in December 1982. It's been in operation for a little over 6 months. We get coal in by rail from the Appalachian fields. These fuels are shipped out now by either tank truck or by railroad tank car. And later this year we will do some barge testing on the Rappahannock River. The two principal objectives of building this plant were first, to gain experience on a commercial size, or semicommercial size and to get sufficient fuel for meaningful boiler tests. Such a test is beginning right now. We have made 400,000 gallons of this fuel in our New Post plant near Fredericksburg and it has been shipped to Memphis, TN where it was sold to the DuPont Co. and in a test, jointly sponsored by the Electric Power Research Institute and DuPoint, they are burning this coal-water mixture in a 60,000 pound per hour steam boiler. The combustion tests are due to start today, August 9. The fuel has arrived and is in good condition so they are scheduled to light it off today. Based upon the success that we fully believe that these tests will have, we will be doing additional marketing and that will lead to the construction of one or more plants to manufacture ARC-COAL.

The second project, which I will cover very quickly, is coal desulfurization. We use standard techniques in getting rid of pyritic sulfur, which as has been mentioned before is organic sulfur in coal. Pyritic sulfur is the sulfur constituent in coal that's so hard to remove. We have developed in our laboratory microbiological techniques at various temperature processes to remove organic sulfur. By varying process conditions, we can remove between 20 and 90 percent of the organic sulfur in the coal. This is still in the laboratory stage. We have applied for a patent covering the microorganism and the process that we use. We have built a very small continuous pilot plant that can produce a few pounds per hour. By the end of this year we hope to have operating a larger pilot plant which will be producing 1,000 pounds per day—excuse me, our existing plant is producing a few pounds per day but we hope to scale that up to a factor of 1,000 by the end of the year. Following success on that level, we would see a continuous scale perhaps at our Fredericksburg facility.

I have used up my time. I would just like to say, in conclusion, that our developments are important to the future of coal and I agree with my friend, Dr. Wolfe, that coal liquids and particularly coal-water mixtures are going to be an important fuel for the use of the United States and abroad. And I feel that these fuels have a very significant potential in really the near future in replacing oil and increasing the use of coal. Second, I believe that reducing the sulfur emissions from coal burning facilities is bound to come. And I believe that technology such as the process that I mentioned and others that are being sponsored elsewhere are going to be important ones for increasing the utility of coal to the consumer.

Thank you, Senator, very much.

[The prepared statement of Mr. Henderson follows:]

PREPARED STATEMENT OF CHARLES B. HENDERSON

Mr. Chairman, members of the Committee, and ladies and gentlemen, I appreciate the opportunity to appear before you this afternoon. It is particularly gratifying to appear before the Chairman, who has been a friend of our company for 25 years.

In my remarks today, I want to tell you about two programs at the Atlantic Research Corporation, both of which should have a substantial impact in increasing the use of coal in the U.S. and abroad. One of these programs, the development of coal-water mixtures as a low-cost liquid fuel is very close to commercialization. The second program, the removal of organic sulfur from coal microbiologically is just beginning to emerge from the laboratory.

Our program to develop coal-water mixtures as a liquid-fuel substitute for residual oil began six years ago. In the early years, it was supported by the U.S. Department of Energy and the Electric Power Research Institute, but for several years all of the funding has been our corporate investment.

The name ARC-COAL has been given by the Atlantic Research Corporation to a large number of combustible mixtures of pulverized coal, water, and certain additives developed for use as a liquid fuel. Rather than the development of a single fuel formulation, numerous formulations have been developed to encompass the use of different coals and to achieve fuels with different properties. The range of moisture-free coal concentrations employed is typically between 70 and 72% by weight, the remainder being water and several additives. These are employed to give a fluidity to the mixture similar to that of motor oil and to prevent the coal particles from settling; they are present in only a small amount. The resulting fuels have been developed as a replacement for residual oil in boilers, both utility and industrial, and in industrial furnaces.

ADVANTAGES OF COAL-WATER SLURRIES

The advantages of coal-water slurries as a boiler fuel are:

1) The ease in handling, transporting, and storing of a liquid,

2) Low cost per unit of energy,

3) Potential for boiler retrofit at low capital cost,

4) Early availability,

5) Independence of foreign raw materials,

6) Capability for integration with coal cleaning,

7) Capability for integration with coal-water slurry pipelines,

8) Small capital requirement for a processing plant,

9) Cost of new boiler much lower than that of coal-fired boiler,

This displacement of coal by oil in the energy market-place between 1940 and 1973 arose, to a large extent, from the simplicity and the resultant economic savings of handling a liquid fuel as opposed to solid coal. Oil can be pumped from one container to a second, stored in tanks, transported via pipes, and easily introduced into furnaces and boilers by injection. Coal-water mixtures have this same ease of handling. Solid coal, on the other hand, requires complex machinery for the loading and unloading of containers and for introduction into furnaces and boilers.

ECONOMICS

To become a marketable fuel, the cost of coal-water mixtures must be significantly lower than the cost of oil. With present-day costs of oil and coal, the ARC-COAL fuels satisfy that objective. The principal factor in determining the cost of coal-water mixtures is the cost of coal. Cleaned-coal delivered to our plant in New Post, VA (near Fredericksburg) costs approximately $65/ton, or $2.24 per million Btu. In production quantitites (e.g. 280 million gallons per year equivalent to one million tons of coal per year) this would result in a fuel price of $2.95) per million Btu. The difference, namely 71 cents per million Btu is the cost of converting the solid coal to a liquid fuel, including amortization, interest, raw materials other than coal, electricity, labor, land costs and profit. In comparison, the current price of residual oil averages $4.50 per million Btu.

THE MARKET FOR COAL-WATER SLURRIES

The principal market for coal-water slurries is as a replacement for residual oil in utilities and industry. Approximately two million barrels per day of No. 6 fuel oil are used in U.S. utilities and industries, largely as a fuel in boilers for the generation of steam. The utility market represents approximately 60% of the market and industry represents 40%. The utility market is localized to a great extent along the East Coast. Much of this market could be conveniently served by barge along the inland waterway.

The industrial market is more diverse but may be more immediate because of a simpler process in conforming to environmental restrictions. A significant industrial market would seem to be present, radiating in all directions from the Appalachian and Mid-West coal fields. Some of these customers would be served by truck or train, at least until pipelines can be introduced.

The principal use for coal-water slurries in the 1980's will be as a fuel for the boiler designed for oil. The boiler designed for coal and previously retrofitted to oil may be an easier market from a technical standpoint, but the oil-designed boiler represents a much larger market. The owner of oil-fired boilers has a number of options, one of which is to continue the use of oil. This leads to zero capital investment but high fuel costs. A second option is to replace the oil-fired boiler with either a pulverized-coal boiler or a stoker-coal boiler. This has a very high capital investment but the lowest fuel costs. Coal-water slurries provide a third option, namely of retrofitting oil-fired boilers to the use of ARC-COAL by the addition of new burners and pumps, the addition of soot blowers and particulate equipment, and provision for ash disposal. This option provides an intermediate capital investment and an intermediate fuel cost, but is projected to be the most cost-effective option of all.

Another important market for coal-water mixtures are furnaces such as in steel plants. It also seems logical that coal-water mixtures will be exported as a liquid fuel in tankers. Offsetting the cost of shipping water will be the great reduction in the capital costs of loading and unloading solid coal.

COAL TYPES

Most of our development effort has been based on Eastern bituminous coals, but successful mixtures have also been prepared from Western coals. Most bituminous coals and some semi-bituminous can be successfully processed.

FUEL PROPERTIES

One of the most important properties of coal-water mixtures is their consistency. They must be fluid in nature so that they can be pumped, transported, atomized and stored like oil. Mixtures of pulverized coal, as normally introduced into coal-fired boilers, and water at a 70% coal concentration have the consistency of wet sand. To achieve the desirable fluid characteristics, it is necessary to select the appropriate additives and to process the fuel properly.

Stability is another important property - coal and water ordinarily don't like each other; to achieve the happy marriage between the two, additives and processing conditions must be selected judiciously. The result is a fuel that will remain stable for several months and for even longer periods with a few hours per week of stirring.

At coal-loadings between 60 and 75% by weight, the thermodynamic properties of the coal-water slurry fuel are very similar to those of No. 6 fuel. At equivalent excess air, the volume of stack gas produced per unit of energy (assuming complete equilibrium combustion) is identical for the two fuels. Consequently, for equal velocities of exhaust gases within a duct of given dimensions, the power output, under ideal conditions, will be the same. Of course the use of coal in an oil-fired unit may require lower velocities to prevent erosion and higher values of excess air for complete combustion. The adiabatic flame temperatures of the slurries are between 180°F and 270°F (100 and 150°C) lower than those of No. 6 fuel oil. The combustion products are also very similar. The addition of water to coal does not contribute to excessive quantities of water in the products of combustion, but instead results in a water-vapor concentration almost identical to that obtained from oil. The CO and NO concentration in the equilibrium combustion products of coal-water are lower than for the other three fuels because of the slightly lower flame temperature. The SO_2 concentration in mass per unit of energy generated is equivalent to that of the parent coal.

We all know that water is not a fuel; it is present in the mixture only to serve as a low-cost liquid vehicle. Vaporization of the water in the fuel uses only a small portion of the energy supplied by the coal - only 3%.

COMBUSTION

Coal-water fuels have been burned at our Alexandria fuel testing facility since October 1979. With the proper burner design, stable flames very similar to oil flames are produced.

Combustion tests on ARC-COAL® have also been conducted at many other facilities including Babcock and Wilcox, the Pittsburgh Energy Technology Center of the Department of Energy, Southern California Edison, Florida Power and Light, Brigham Young University, TRW, Ohio State University, and MIT. ARC-COAL® has also been shipped overseas to Japan, the United Kingdom, France, and Belgium. In the UK, ARC-COAL® was successfully burned in a pressurized fluidized bed; at TRW in a slagging combustor. A successful 8 hour test was recently conducted in a West Virginia steel plant in which ARC-COAL® was injected in the tuyeres of a blast furnace to conserve coke.

PROCESSING AND SCALE-UP

The Atlantic Research Corporation currently has two pilot plants in operation. The smaller one designed for approximately 100 gallons per hour has been in operation since January 1980. The second plant, which became operational in December 1982, produces 25,000 gallons per day and is located in Spotsylvania County, Virginia, very near Fredericksburg. Coal is received from the Appalachian coal fields by rail car. The finished fuel is shipped out either by rail or by truck. Later this year, shipment by barge on the Rappahannock River will be tried as an experiment.

The two principal objectives of building the Fredericksburg plant are to gain experience on a commercial size and to provide sufficient fuel for meaningful combustion tests. Such a test will be conducted in July and August of 1983 sponsored by the Electric Power Research Institute and E. I. DuPont de Nemours and Company Inc. who will conduct a 30 day test in a 60,000 pound per hour boiler at a DuPont chemical plant in Memphis. The test is intended as a dress-rehearsal for an even larger test in a utility boiler. 400,000 gallons of fuel for the test will be provided by rail from the ARC Fredericksburg fuel preparation plant. Almost all of the fuel has been manufactured, and 100,000 gallons are already in transport. The remaining fuel is in storage in two 150,000 gallon fuel tanks at our facility.

Considerable interest in the EPRI-DuPont test has been evidenced by the electric generating utilities.

Based on marketing being conducted now and subsequent to the tests discussed above, the Atlantic Research Corporation will build and operate one or more plants to manufacture ARC-COAL.

COAL DESULFURIZATION

A second project, biological desulfurization of coal, is currently being tested in a small pilot plant and will be covered only briefly.

Hydrocarbon fuels, such as coal and oil, contain sulfur as an undesirable contaminant. Although low sulfur oils (0.3%) are found in nature, the total sulfur content of coal is seldom less than 0.8%, particularly in coals from Appalachia and the Mid West. Gaseous combustion products of these fuels contain sulfur which require expensive scrubbing if they are to be removed before release of these gases into the atmosphere. Reducing the sulfur content of fuels prior to combustion could provide an economical alternative to flue gas scrubbers.

Sulfur is present in coal as inorganic pyritic sulfur, water soluble sulfates and as organic sulfur. Much of the inorganic pyrite and sulfates can be removed from coal by standard coal cleaning techniques. i.e. washing, heavy media separation, froth flotation. Organic sulfur is much more difficult to remove because it is chemically bound to the coal and is insoluble in water.

Scientists at our company have developed a microbiological technique which results in substantial reductions in the organic sulfur found in coal. An application has been filed for a patent covering the microorganism and the process used for biological desulfurization of coal. Biological treatment of coal results in conversion of the organic sulfur to water soluble products which can be removed from the coal by standard washing procedures. Preliminary tests indicate that the energy and volatile contents of the coal are not affected by the biological treatment.

A continuous pilot plant has been built in our laboratories to process a few pounds of coal per day. The sulfur content of low sulfur coals and of high sulfur coals has been reduced significantly by this treatment. It is anticipated that a larger pilot plant for processing of a thousand pounds of coal per day will be constructed before the end of 1983. Scale-up of this process to commercial size would be an important step forward in producing low sulfur coal-water fuels.

CONCLUSIONS

In conclusion, a liquid fuel based on a slurry of pulverized coal in water has been developed. This liquid fuel has potential for replacing No. 6 fuel oil in steam boilers and furnaces. The fuel is inexpensive, uses no imported raw materials, is readily transportable and can be exploited in the near term with very low capital requirements. Studies to determine the effect of this fuel on the output and efficiency of oil-designed boilers and to determine retrofit costs will be undertaken in the near future.

A microbiological process for removing organic sulfur from coal is currently being developed. Although this process is not as well defined as the ARC-COAL process, it holds great promise as a means of reducing the acid forming combustion products from coal.

Senator **Warner**. We now proceed to the panel on "Coal Using Utilities." We are to be joined by Mr. Samuel C. Brown, senior vice president for corporate technical assessment, Virginia Electric Power; Mr. James W. Hock, manager of coal, Florida Power & Light; Dr. William D. Harrison, senior vice president, Southern Company Services; and John F. Kaslow, senior vice president, New England Electric System.

STATEMENT OF SAMUEL C. BROWN, JR., SENIOR VICE PRESIDENT, CORPORATE TECHNICAL ASSESSMENT, VIRGINIA ELECTRIC & POWER CO.

Mr. **Brown**. I appreciate the opportunity to come here today, Senator, to talk about some of the things that Virginia Electric Power Co. has done very recently in connection with coal. Some of you in the audience may be familiar that we have gone through a coal conversion program where we have converted 1.8 million kilowatts back to coal. And in addition, we will be taking 450 kilowatts converted back to coal generating capacity and later, about 200 more. This means that by 1987 we will have well over 2,000 megawatts converted from oil to coal.

Senator **Warner**. Would you give us a percentage of what that relates to in terms of your total output?

Mr. **Brown**. Our total output is approximately about 10,000 and I'd say, at this time, it would be about 50-percent coal and 50-percent nuclear.

Senator **Warner**. And you hope to be where in 1987 in those ratios?

Mr. **Brown**. We will expect to up to about that ratio at that time.

Senator **Warner**. I see.

Mr. **Brown**. In 1973, just prior to the oil embargo, we were involved in a rather extensive oil firing program. We were able, prior to that time, to design our units to handle both coal and oil to sort of keep the cost to the ratepayers flexible. In 1969 the oil price was much more attractive. We made major conversions at that time and switched units from coal to oil. At that time, we were generating 50 percent of our system by oil. Last year, however, we used 4 percent oil which is sufficient for lubricating purposes and so on. There's been a massive thrust at getting off of oil in the Vepco system. The oil to coal conversion costs over 3 years amounted to $280 million. Over this 3-year period, our ratepayers saved $540 million, by going back to coal. We will be, in the very near future, probably by 1986 using between 4½ and 5 million tons of coal a year. We expect to continue increasing the use of coal. As most of you know, the nuclear option is fairly well out and has been shelved for the time being. That's very unfortunate but that's the way the cookie crumbled. We must keep our cost generation in line.

Senator **Warner**. Well then, your growth in power will be from a coal source?

Mr. **Brown**. Our expected growth, with the exception of our hydroelectric, which is our Bath County pump storage unit, will be from the coal market. We must keep our costs in line with the price variance regulatory impacts that we are continually up against and some of those regulatory changes are definitely nonrevenue bearing and they don't go to improve the situation any, at all. We've got to continually follow this and I ask you, Senator, to make sure that what we do is needed. We had just recently a rate case, and the regulators said they did not feel that the R&D efforts that the company supported was a legitimate expense until such time as these particular items that were being researched were turned into a paying proposition. I think this is a bad attitude and I hope that the staff and the Commission will see it that way. We are having a load growth through the 1990's of about 2 or 3 percent. And to meet this load growth we are looking at alternate energies, about 13 different programs. Two of the main ones involve coal and are in the area of coal gasification. We have heard from Mr. Henderson on coal-water mixtures. We are very excited about coal-water. This is the 70 to 30 mixture. We are also looking very seriously into micronized coal. And at those various transport means for methanol and CO_2. We feel that the ultimate for the coal-water fuel is really the fuel of the future. We believe an east coast market for coal-water is there. We feel that coal-water technology can be developed to be fired inside of oil fired furnaces. Now, oil fired are smaller than the conventional coal fired furnace. They are smaller in volume. We believe that coal can be cleaned and be processed to meet the needs of some of our oil burning utilities. We think that burning this coal-water mixture in units is going to be a big help in those areas that don't have the storage areas for the sludge, or large ash pile. Mainly, those units are in the urbanized areas that are low fire or are coal fired boilers and don't have the facilities that they once had because of urban growth. I think there's a strong potential that this fuel could tap a market, which has a maximum potential that could be as high as 150 million tons a year. That's looking all the way up and down the East Coast and not considering the export market. Virginia has very rich reserves of a grade of coal that is low in sulfur. We think that this material could be shipped, could be pumped, and could be stored like oil. I would have no objection at all if some of the sheiks were to come to the Appalachian region and some of that oil wealth were to come to Virginia and West Virginia and other states that are producing coal. I think its a good possibility, too, but we need to develop technology in this area.

The coal-slurry pipeline is a new possibility on the horizon for coming in matching the Stagger's Act. The railroads have been deregulated. The opportunities now are to apply some competitive form of transportation of coal. I think if we are progressing toward what I call the new coal economy, we've got to have an alternate means of transportation. The coal pipelines are needed to provide the competition in the shipment of coal. Both to improve the markets overseas and our competitive status on those markets as well as to reduce the cost of coal. We at Vepco estimate in our system alone, we're looking at a reduction of about $50 million a year that could be saved if the coal was transported through coal-slurry pipelines. Today we have a State regulation that does not allow us to do this. Federal legislation is pending. I think that in the name of competition, which this country was built on, we need an alternate means of transporting fuel. I can assure you that if it is not profitable to build it, it will not be built. I think the recent case in Arkansas, where Arkansas Power accepted a very fine contract with a coal company in lieu of part of a coal-slurry pipeline was a good example that competition was needed. I think that in the area of coal-slurry pipeline and you, Senator, as an engineer of Virginia Society of Professional Engineers, I'd like to pass this study down to you. This is a prepared study called "Virginia Coal Transportation Study" and it's a very comprehensive presentation of the facts. I'd like to congratulate Don Caskie, a member of the professional engineers who produced this study. On this study were members of the railroads, the utilities, the consultants from universities and government. Dr. Hibbard was very instrumental in making the facts in here available for the coal industry. And his group participated from the Virginia Center for Coal Research. We are very proud of this report. It's one report that I think the railroads can pick up and the utilities can pick up and get, pretty well, the unbiased facts.

Senator WARNER. That reminds me of my history professor, Lee, who keeps a book on his desk that is called "The Unbiased History of the War Between the States From the Southern Point of View." [Laughter.] You are free to espouse those views and I may have to give equal time to the rail industry. Indeed, in fact, I think this is a subject that is very important to the United States. There are bills pending in the Senate today regarding coal-slurry pipelines. They were reported out of the Senate Energy Committee, of which I am a member, favorably. As you stated, Virginia has a prohibition on coal-slurry pipelines. It is by statute opposed to a deregulation at the moment and the Governor is trying so far as I can determine, in a very evenhanded way to study this issue. He has ordered another study, and hopefully this issue will be resolved in the not too distant future. It is a very very difficult one to come to grips with.

Mr. BROWN. I realize that. I would like to bring up, and I think everybody before me has at least said a word on acid rain. I would just like to add some caution to that. We are looking at a tremendous cost impact. The Sikorsky-Waxman bill, and the Mitchell bill, are bills on acid rain that are now pending. I think that we have to be very attentive to the cost benefits of this legislation. We have had acid lakes for a long time and they have been fixed by lime for a long time which has been the wrong technology. I think we need to look into coal cleaning. There was some mention given here about coal cleaning and I think its extremely important. I might mention one thing in connection with the tax exemption. You can get a tax exemption on a scrubber but you can't get a tax exemption on bonds financing a coal cleaning plant which doesn't make good sense to me. One of them, the coal cleaning, does more for keeping the boiler and adding to the reliability of the unit then the scrubber does. The scrubber is after the fact. And I think that we ought to look at that and see if something can't be done there.

Well, I think, to get on with this new coal economy as I'd like to call it, we need to clean the coal at the mine, we need to minimize the use of coal as far as burning it and transporting ash and other things that we can't handle. We need to leave that at the mine where it can be properly disposed of and handled. What we need to do is also bring into being the fluidized bed combustion unit which would be generating coal from the throwaway portion of coal that is shipped to the marketplace. The fluidized bed would burn the dregs and put it into an ash form that can be stored and put away in a safe manner and reduce the SO_2 and produce electricity at the spot at the mine or at the cleaning plant. I think this has got a lot of possibility and there is strong evidence that fluidized bed combustion is moving along very strongly. This way we would be shipping to the marketplace very valuable product and not a lot of waste that we then have to find a place to dispose of in a highly urbanized area which is becoming more and more of a problem. And I think that we can ultimately deliver the clean product.

Now, to go back to one more thing. Vepco, as many of the utilities are, participates in the Electric Power Research Institute. In the next 5 years, the Electric Power Research Institute will spend $612 million in coal research. This is utility money the ratepayers have put up to develop areas in the coal industry. This is going into coal gasification, coal retrofaction, coal cleaning, particulate control, advanced flue gas desulfurization system, atmospheric fluidized bed combustion, and the new limestone injection multistage burner. To go back again to rain, there are new technologies down the road to combat this problem. The acid rain problem, as far as the utilities contribution, may not be cleaned up overnight, but you can't run the chance of breaking the industry by trying to clean it up overnight. I think over a long period of time with these new technologies being pushed, we are going to have the technology to clean it up. And I appreciate the opportunity of coming here today.

[The prepared statement of Mr. Brown follows:]

REMARKS OF
SAMUEL C. BROWN, JR.
SENIOR VICE PRESIDENT-CORPORATE TECHNICAL ASSESSMENT
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
SENATE ENERGY AND MINERAL RESOURCES
SUBCOMMITTEE FIELD HEARING
BLACKSBURG, VIRGINIA
AUGUST 9, 1983

Vepco is nearing the end of a massive shift of fuels away from oil to nuclear power and coal.

At the beginning of the 1970s, oil was plentiful, less expensive than coal, and had fewer environmental constraints than coal. We had built our generating units so that they could be switched easily between coal and oil. Consequently in 1972 Vepco produced 50 percent of its electricity from oil.

As oil prices soared through the 70s, we began what became the largest oil-to-coal conversion program of any utility. We have already converted 1.8 million kilowatts of capacity. Today we have twelve coal units operating, 7 of which have been converted from oil, and we plan to convert three more units to coal by 1985. Two more conversions are planned for the late 1980s.

As a result of these conversions, a comprehensive fossil unit improvement program and increased nuclear generation, Vepco reduced its oil usage last year to only 4 percent of energy supply. During the last three years we spent nearly $280 million on coal conversions and improvements, but we effected $540 million in fuel savings to our customers during that same period—nearly $2 saved just in that three year period for every dollar that we used.

The drastic change in our use of fuels has allowed us to keep our rate increases during the 1980s well below general inflation, despite severe cost pressures.

Our success is vividly illustrated in a comparison of Vepco's performance with the performance of the 19 other largest utilities and with the economy generally. While Vepco's average price has increased only 8 percent during this decade, the average Consumer Price Index has gone up 17 percent and the average price of the 19 other largest utilities has increased more than 28 percent.

Our average price is now below the national average, and our fuel costs are lower than those of other Virginia utilities.

As a result of oil-to-coal conversions and unit improvements, Vepco expects its use of coal in its Virginia plants to increase from 3.7 million tons in 1982 to between 4.5 and 5 million tons in 1986, depending on the economies available from purchased power. Coal use should also increase as the result of improvements at our Mt. Storm coal-fired generating station, which is a mine-mouth plant located outside our service area.

Vepco expects to continue to use large quantities of coal to the year 2000 and beyond.

Through coal conversions and improvements, the percentage of electricity generated from our coal units will increase to more than 50 percent by 1986. Our economical nuclear and coal-fired generating units will provide the electricity for huge pumps at the Bath County Pumped Storage Project. These pumps will use coal-generated power produced during off-peak hours to pump water into a man-made mountain lake for energy storage. During periods of high electricity demand the water can be released, the pumps are reversed to become generators, and peak loads can be met in an economical manner.

These are our plans for the near future. In the long-term the problem will be to keep our price increases below the inflation rate even while meeting increases in electricity demand and responding to increasingly expensive regulatory requirements.

The decline in overall energy use per unit of economic activity since 1973 has been frequently noted, but many observers have lost sight of the fact that electricity demand and use has continued to increase at about the same rate as general economic activity.

The consensus of forecasts for electricity demand growth during the next decade lies in the range of 2.6 to 3.2 percent a year—below the actual growth of demand in the 70s when the economy was weak and electricity price increases were large. Vepco's forecast is for demand to increase at 2 to 3 percent a year through the 90s.

How will utilities meet this additional demand?

The nuclear option has been shelved for at least a decade in the future. Oil prices are expected to resume real increases at least by the early 90s. The cost of new generating technologies is still high.

In this context utilities will depend chiefly on coal for additional electricity generation in this century. Since coal is expected to play an increasingly important role in the future, utilities are searching for improved and new technologies that will enable them to hold down the life-cycle cost of coal-fired generation.

Vepco is now conducting a wide-ranging study of alternative energy sources to determine the lowest cost combination of options for meeting or reducing future electricity demand. This study is comparing 13 alternatives with the cost of conventional coal-fired generation.

Two of the alternative options being studied involve coal. One is combined cycle generating systems that used gasified coal as a fuel. In a combined cycle system the hot gases issuing from a gas turbine, which have already been used to spin one generator, are reused to heat steam and produce electricity by running a second generator.

The second option under study is coal-water fuels being developed for use in boilers designed exclusively for oil and in other units that no longer have the space requirements to burn a solid fuel. The potential for this "fuel of the future" is tremendous, as high as 150 million tons of coal per year on the East Coast alone. Some large engineering and manufacturing companies, such as Babcock and Wilcox, Combustion Engineering, Westinghouse and others, and smaller firms such as Atlantic Research and United Coal, are actively pursuing various aspects of coal-water fuel technology.

Coal-water fuels consist of about 70 percent coal, 30 percent water and additives. Coal-water mixtures can be pumped, handled and stored like oil, which solves the problem of finding storage space for coal on small plant sites.

Vepco is exploring the possibility of conducting a test burn with coal-water fuel at one of its existing generating units. We still have two large oil units that will not be converted to coal even after our conversion program is complete. Just one of these oil units burning a coal-water fuel could use as much as 2 million tons of coal a year if it were economical enough to use as a base-load unit.

In contrast to these new technologies, coal pipeline technology is readily available and capable of saving electric utilities and their customers millions of dollars each year. Now that the railroads have been largely deregulated by the Staggers Act of 1980, coal pipelines are needed to provide the restraining arm of competition.

A number of studies show that pipelines could provide an economical alternative to rail. We estimate that a pipeline could save our customers as much as $50 million initially and more in future years.

Coal pipelines could help consumers indirectly by making the price of coal more competitive and helping to reduce the use of imported oil. And the possibility of an economical means of transporting the vast U.S. coal reserves could have a restraining influence on world oil prices.

This effect on oil prices would be even larger as techniques for using coal-water fuels are perfected. Then electric utilities and other large users of fossil fuels could switch easily between coal-water fuels and heavy oil, depending on market conditions at a particular time.

Coal pipelines could be used in combination with other new technologies to provide even greater economies. Since the cost of grinding and processing coal would be paid for through lower transportation costs, the cost of producing a coal-water fuel would be cheaper because much of the grinding and preparation would already be done.

In addition, there would be greater incentive to use new coal cleaning technologies to meet enviromental standards at coal-fired generating stations, and higher quality coal could be transported through the pipeline with less cost per BTU. The combination—coal pipelines, coal cleaning and coal-water fuels—would work together synergistically to increase the attractiveness of coal-fired generation as a major option in meeting current and future electricity demand.

In some instances, especially with older coal units that are used only sporadically, coal cleaning may enable those units to be used in the face of stiffer environmental regulations that would otherwise require heavy investment for compliance by conventional means. Installing expensive scrubbers on a 40-year old coal-fired unit that is little used would be a large expense for a small gain, but the investment in a coal cleaning facility could be easily recovered if it supplied a number of units with coal clean enough to reduce the need for scrubbers.

The mention of scrubbers naturally triggers concerns about acid rain and the possibility of acid rain legislation. Since coal technology is beginning to advance after decades of neglect, it would be a mistake if Congress were to mandate, for example, the use of scrubbers on a certain number of coal units above a certain size. Rather, utilities should be able to choose among available technologies.

If there is to be acid rain legislation, it should allow utilities to meet the required standards in the most cost-effective manner. Mandating scrubbers may protect high sulfur coal producers, but coal cleaning technologies may provide a less expensive way of preserving utility markets for those same producers.

Further, if acid rain legislation is enacted, it should include a comprehensive, continuing program of study on a scale that will allow a cost-benefit analysis of the reductions that are effected. Even the most recent report on acid rain by the National Research Council pointed out the lack of scientific data in relation to the enormity of the choices to be made.

As coal technology develops, some observers have envisioned a total coal economy much like the existing petroleum economy, with liquid coal refineries, coal pipelines, water transportation, coal cleaning, and coal-water fuels. Another promising element in this systematic use of coal is fluidized bed combustion.

If coal is to be fully utilized without costly scrubbers, deep cleaning of coal to remove most of the ash-forming and sulfur-containing mineral matter would be necessary. This beneficiation process would be more attractive if a means could be developed for burning the high-mineral coal that is left after cleaning.

Fluidized bed combustion allows the use of low-grade fuels by controlling the chemical reactions that occur during coal burning itself. Undesirable gases that could escape to the atmosphere either are not formed or are converted to other compounds during combustion.

Fluidized bed combustion using low-grade fuels has been demonstrated here and abroad, and the ash-limestone mixture discharged from the fluidized bed boiler has commercial value. Naturally it would make sense to locate a fluidized bed plant near a coal cleaning facility to keep transportation costs low.

But before a new coal economy can develop, much utility-specific and site-specific research needs to be done.

The research and development needed for coal pipelines -- a necessary part of the new coal economy -- in the Eastern U.S. will not be done until Federal eminent domain legislation is enacted. Private funds will then flow into these projects. There will be no need for federal assistance.

Similarly, coal-water fuels will be developed by the marketplace depending on the level of oil prices.

Coal cleaning and fluidized bed technologies, however, are benefitting from and could use increased Federal research funds. No single utility on its own can afford to develop these technologies to a commercial status, and the entire nation would benefit from them.

Congress should correct the existing bias against front-end methods for reducing coal emissions. Currently, utilities can finance pollution control devices such as electrostatic precipitators with tax-exempt bonds, but a facility to clean coal before it is burned and accomplish the same result is denied this tax-exempt status. Since coal cleaning could help reduce transportation costs as well as protect the environment, the continued disadvantage of coal-cleaning facilities could inhibit development of a coal economy.

Our national leaders should encourage a more enlightened view of utility research and development on the part of state regulators.

The Electric Power Research Institute, the research arm of the electric utility industry, is heavily involved in coal-related research. Over the next five years EPRI plans to spend $612 million, 36 percent of its budget on coal research. But in Vepco's most recent Virginia rate case, the staff of the State Corporation Commission challenged our contribution to the Electric Power Research Institute, which is funded by electric utilities across the country. The value of the research to us and our customers from this organization far exceeds the cost of our contribution.

The response of the Virginia Commission to utility research expenses is by no means unique. At a time when American technology is being challenged on all fronts, research and development of our nation's largest energy research should be encouraged, not inhibited.

The U.S. has much to gain by being in the forefront of coal research and the development of a comprehensive coal economy.

# # #

Senator **Warner**. As far as breaking the industry, in your situation in all probability you'd be able to pass those costs on, whatever may be imposed by Federal statute, to your consumers. So, in a sense, they're the ones that are going to pick up the ultimate tab, whatever we do legislatively, or much of the tab on acid rain, is that correct?

Mr. **Brown**. That's true. That these sort of technologies will be passed through. Maybe breaking the industry is the wrong term, but breaking the industry's heart.

Senator **Warner**. The thing about the acid rain is we've got to bring home to the consumer the potential costs in the use of energy that you supply, as the result of some of these bills. Perhaps during lunch you could give me some assessment of the degree to which you all would be interested in a brief analysis on these various pending bills in Congress. I known them quite well and we have Mrs. McGill here, of my staff, who is highly familiar with this legislation.

Now, we have Mr. Hoch.

STATEMENT OF JAMES W. HOCH, MANAGER OF COAL, FLORIDA POWER & LIGHT CO.

Mr. **Hoch**. Thank you, Mr. Chairman. My name is Jim Hoch. I'm manager of coal, Florida Power & Light Co., Miami, FL.

Senator **Warner**. We appreciate your coming up here.

Mr. **Hoch**. My purpose in presenting testimony here today is the apprise the Senate Subcommittee on Energy and Mineral Resources of Florida Power & Light's interest in obtaining coal fired fuels capable of displacing or diminishing our consumption of fuel oil as a generating fuel in oil designed use. The FP&L is dependent on fuel oil for most of its electric generation requirements. While some other Florida utilities have found coal to be a viable and economic fuel in their system, the location of the FP&L service area, which is far from the sources of coal, and easily accessible to the traditional Caribbean Basin fuel oil sources, is one of the most important reasons for our dependence on fuel oil. From both economic and technical points of view, fuel oil is a more desirable fuel since it can be obtained cheaply and reliably and allow the construction of simple, reliable, and clean powerplants. Since 1973 when OPEC first flexed its muscles, the price of oil has risen over 1,500 percent. While it is true that the prices we presently pay for No. 6 fuel oil have subsided over what they were just 12 months ago, we view this as a temporary respite during which time we must accelerate our investigation into these alternative fuels. Our current oil price forecast depicts continuation at the present level through the mid 1980's. Yet even with a lessened marketing control by OPEC, we predict resumption of significant price increases in the second half of this decade, as oil and natural gas reserves decline, while population growth increases the energy demand. Additionally FP&L, like most other businesses, is faced with high cost of capital. Unlike most other businesses, the utilities cannot easily postpone their needed capacity expansion due to the mandate of providing reliable electricity service. This means that utilities are, in the capial market, paying current interest rates to meet this demand for expansion. When special circumstances such as the requirement to switch to alternative fuel types are added, the burden of raising capital is even greater. Hence it is imperative that we, in the electric utility industry, search for new technologies which result in lower capital cost requirements. In 1980 FP&L pioneered the concept of burning coal/oil mixtures [COM], in oil designed utility boilers by operating our Sanford 400-megawatt power station on COM for 2 months and we did it at up to full power rating. This test of COM was conducted in order to evaluate the impact that a coal based fuel would have on a utility boiler that was designed and constructed to burn primarily fuel oil, as well as to demonstrate the economics of this new fuel concept. The results of the test, which was completed in April 1981, proved that COM was technically feasible. However, based on economics and the long-term fuel planning strategy, its been determined that COM should not comprise a part of FP&L's overall long-term fuel mix. From a long-term fuel planning strategy an electric utility must have diversified fuel sources to mitigate the effects of a total supply interruption with regards to any single fuel. By utilizing COM, we would still require oil in addition to the coal at every plant so converted and fuel prices would still be dependent, to a significant extent, on fuel oil prices. So coal/water mixtures [CWM] would appear to theoretically solve this FP&L dilemma with respect to converting from oil to coal. CWM is still a liquid and a utility would not require a completely new handling system but could instead convert its existing oil distribution and storage system. Since CWM contains no oil, any plant converted would be completely independent from fuel oil requirement. It is for this reason that FP&L is supporting research into coal cleaning and slurry technology. Coal cleaning combined with coal slurry technology could offer the opportunity of manufacturing a truly innovative substitute for fuel oil. To date, most deep cleaning coal technologies have added significantly to the cost of the coal and it is therefore important to develop a technology which is affordable. At the present time, little CWM is commercially available and it is quite impossible to predict with any degree of certainty what the cost of such cleaning and slurrying will add to the product coal. We do, however, have some fairly good order of magnitude estimates of what plant modifications would have to be made in order to burn CWM and what the CWM processing costs might be. When we compare these costs to the oil costs we can then calculate whether CWM shows any economic application within FP&L. We are not ready to publish any numbers, however, I can say that the data indicates that CWM could indeed be economically attractive if future oil prices move up relative to coal, as we predict they will.

In order to verify the technical and economical feasibility of CWM as a boiler fuel FP&L's CWM project team has developed a plan for a detailed CWM evaulation. Our plan consists of four phases. Phase 1 is an evaluation of CWM fuel to see if it can be lower cost alternative for any of our plants. Phase 2 would assess competitive technologies and the business arrangements for a CWM supply. We have developed financial and technical information needed to see if uncertainties and risks of CWM can be reduced to an acceptable level and further, we would formulate detailed plans, schedules and cost estimates for the potential demonstration of CWM and even a conversion program.

Senator WARNER. Will you have an opportunity to have lunch with Mr. Henderson? He seems to have the product along that line.

Mr. HOCH. Mr. Henderson's firm and mine are having detailed discussion now.

Senator WARNER. From what he told us this morning, it looks like hand in glove what you're looking for.

Mr. HOCH. You are exactly right.

Senator WARNER. That's good. Maybe we can have a marriage out of this here. [Laughter.]

Mr. HOCH. He's one of several, I should add.

Senator WARNER. You just wait and see how competitive we can be here.

Mr. HOCH. Phase 3 is that phase which we would hope to select a CWM supplier and convert one of our 400-megawatt units for demonstration purpose. Phase 4, then, would result in burner conversion of not only demonstration unit but other units as deemed applicable. Phase 1 has been completed and we're enthused about the prospect of coal/water mixture being implemented as a demonstration fuel but I would assess FP&L's level of confidence at present to something around 60 to 65 percent. No utility could risk a multi-hundred-million-dollar conversion to this new fuel with such a level of confidence. Therefore in recent past weeks, FP&L's management has made a commitment to attempt to raise this level of confidence to something like 90 to 95 percent by authorizing an ambitious scope of work which was described earlier as phase 2. Phase 2 will take anywhere from 12 to 16 months and FP&L is going to fund this phase of activity up to $1,500,000. It's anticipated that other interested parties, such as Mr. Henderson's company, will also contribute services, time and funds to assist in this advanced scope of work. During phase 2, we intend to conduct an independently witnessed comparative test program among those entities considered to be willing and capable prospective CWM processors, among them Atlantic Research. Hopefully, phase 2 will produce a viable business approach to CWM, as a result of discussions among those who propose to participate in this industry, the CWM industry. It will also permit development of plans and schedules for FPL's use of CWM both at the demonstration level and as a permanent conversion fuel. Most importantly, phase 2 work is intended to give us a detailed technical and economic perspective of what we need in order to decide how to proceed with full scale tests of CWM at one of FPL's large powerplants. The cost estimates for more prominent and prospective CWM processors reveals the significant savings that we have shown could materialize. As we've already heard today, some processors are boasting of $3 to $3.25 million Btu in 1983 dollars when they have achieved full commercial CWM status. We have tried to temper their optimism in our own estimates but we are encouraged by the economics that these figures suggest when compared to our oil price scenarios.

Another difficulty factor which we have had some difficulty assessing at this time is the phenomenom of acid rain. And, simply stated, any legislation which would require FPL indiscriminately or unnecessarily to retrofit our 450-megawatt units with flue gas desulfurization apparatus would, in all likelihood, destroy any economic incentive that we might have to convert those units to CWM or any other coal variety fuel. The additional cost of those scrubbers compounded by the fewer years of useful life left from these units would eschew the total costs such that coal variety fuels would be rejected in favor of continued use of fuel oil.

In summary, Florida Power & Light views coal variety fuels as the preeminent alternative to oil in a great many of our oil designed units. We have nine 400-megawatt units, all of the same basic design. In addition, we have four 800-megawatt units that have shown significant promise as conversion candidates for this CWM fuel. Under phase 1, our base case assumes conversion of two 400-megawatt units and two 800-megawatt units, or a total of 2,400 megawatts. In this scenario, we would use 500 million tons of coal per year. One can easily see that oil designed units coverting to coal, or coal derived fuels represents a potential market without equal in these days of slow utility expansion. Mr. Brown referred to the fact that we might use as much as 150 million tons a year. FP&L has followed the endeavors of this subcommittee focusing on issues relative to increased coal usage and we pledge to continue our look to coal as an alternative to the OPEC stranglehold. Thank you..

[The prepared statement of Mr. Hoch follows:]

Testimony of James W. Hoch

My purpose in presenting testimony here today is to apprise the Senate Subcommittee on Energy and Mineral Resources of Florida Power & Light Company's (FPL) interest in obtaining coal-derived fuel capable of displacing or diminishing our consumption of fuel oil as a generating fuel in oil-designed units.

Historically, FPL has depended on fuel oil for most of its electric generation requirements. While some other Florida utilities have found coal to be a viable and economic fuel in their systems, the location of the FPL service area, far from the sources of coal and easily accessible to the traditional Carribbean Basin fuel oil sources is the most important reason for our dependence on fuel oil. From both economic and technical points of view, fuel oil was a more desirable fuel since it could be obtained cheaply and reliably and allowed the construction of simple, reliable and clean power plants.

Since 1973, when OPEC first flexed its muscles, the price of oil has risen over 1500 percent.

While it is true that prices we pay for #6 fuel oil have subsided over the last 12 months, we view this as a temporary respite during which time we must accelerate our investigation into alternative fuels. Our current oil price forecast depicts a continuation of present levels through the mid-80's. Yet, even with a lessened market control by OPEC, we do predict a resumption of significant price increases in the second half of this decade, as oil and natural gas reserves decline, and world wide population growth increases energy demand.

Additionally, FPL, like all other businesses is faced with high costs of capital. Unlike most other businesses, utilities cannot easily postpone needed capacity expansion due to their mandate of providing reliable electric service. This means that utilities are in the capital market paying current interest rates to meet this demand for expansion. When special circumstances such as the requirements to switch to alternative fuel types are added, the burden of raising the needed capital is even greater. Hence, it is imperative that we in the electric utility industry search for new technologies which result in lower capital cost requirements.

Based on preliminary engineering studies which we have had performed by an independent engineering firm we now feel that we have some understanding of what it would cost to convert each of our nine 400 MW and four 800 MW power plants to burn pulverized coal. It appears to be technically feasible, but would require huge expenditures. We also have assessed the increased operating and maintenance cost we would experience along with the potential for reduced availability related to burning coal vs. oil. But for FPL this does not represent nearly all of the incremental costs since we are geographically located the farthest from the coal fields and have no readily available transportation system for delivering coal to our various plant sites. Therefore, in addition to the actual capital cost of converting our power plants, the increased operation and maintenance cost, the potential lowering of our unit availability (and in the case of our 800 MW units potentially derating the boiler itself), we must also pay for the development of a coal handling and distribution infrasturcture in terms of the associated high transportation cost for coal. Naturally, if there is any way to avoid the high cost of having to convert to straight coal, while still allowing us to economically reduce our dependence on oil, we would like to do it.

In 1980 FPL pioneered the concept of burning coal oil mixtures (COM) in an oil-designed utility boiler by operating our Sanford 400 MW power station on COM for 12 months, on line, at up to full power. This test of COM was conducted in order to evaluate the impact that a coal base fuel would have on a utility boiler designed and constructed to burn primarily oil, as well as to determine the economies of using this new fuel type.

The results of that test which was completed in April of 1981, proved that this new fuel type was technically feasible. However, based on economics, and long term fuel planning strategy, it was determined that COM should not comprise part of

FPL's over all long term fuel mix. From a long-term fuel planning strategy point of view, an electric utility must have diversified fuel sources to mitigate effects of a total supply interruption of any single fuel type. By utilizing COM we would still require oil in addition to coal at every plant so converted, and fuel prices would still be dependent, to a significant extent, on fuel oil prices.

Our COM experience however, did allow us to develop engineering cost comparisons between using COM vs. straight coal. By examining these capital conversion and operating costs we have determined that it was COM's liquid form which made the cost of plant modifications relatively inexpensive for our use vs. straight coal.

Coal water mixtures (CWM) would appear to theoretically "solve" FPL's dilemma with respect to converting from oil to coal. Since CWM is a liquid, a utility would not require a completely new material handling system but instead could convert its existing oil distribution and storage system. Since CWM contains no oil, any plant converted would be completely independent from fuel oil requirements.

It is for this reason that FPL is supporting research into coal cleaning and slurrying technology. Coal cleaning, when combined with coal slurry technology, could offer the opportunity of manufacturing a truly innovative substitute for fuel oil. Of course, the question has been raised; "can you burn water in our units?" A number of successful burns have been conducted in small-scale tests. We have also been working with various architect/engineer firms to develop a description of what we think a cleaned CWM should be like and it is their opinion as well as that of the manufacturer of our boiler, that, if the ash content can be reduced to 2-4%, and the product coal has an initial ash deformation temperature of 2400 to 2600F reducing, and a heating value of 14-15,000 BTU'S per lb. dry basis, CWM can indeed be burned with relatively modest plant modifications. So, CWM may be technically feasible but is it economically feasible?

To date, most deep coal cleaning technologies have added significantly to the cost of the coal and it is therefore important to develop a technology which is affordable. At the present time, little CWM is commercially available and it is quite impossible to predict with any degree of certainty what cost cleaning and slurrying will add to coal. We do, however, have some fairly good order of magnitude estimates of what plant modifications would have to be made in order to be able to burn CWM, and what CWM processing might cost. When we compare these to the costs of remaining on oil or converting the same plant to pulverized coal burning, we can then calculate whether CWM shows any potential for economic application by utilities.

While we are not ready to publish any numbers, I can say that the data indicates CWM could indeed be economically attractive if future oil prices move up relative to coal as we predict they will.

In order to verify the technical and economic feasibility of CWM as a boiler fuel, FPL's CWM project team has developed a plan for a detailed CWM evaluation.

FPL's plan consists of four (4) phases, with the following objectives:

Phase 1 - Evaluate if CWM fuel can be a lower cost alternative than oil for any FPL plant.

Phase 2 - Assess competitive technologies and business arrangements for a CWM supply. Develop financial and technical information needed to see if uncertainties and risks of CWM can be reduced to an acceptable level. Formulate detailed plans, schedules and cost estimates for a potential "staged" CWM demonstration and conversion program.

Phase 3 - Selection of a CWM supplier and conversion of one 400 MW Unit to CWM fuel for a one year long test.

Phase 4 - Development of a program for conversion of a number of oil fired plants to CWM.

Phase 1 has been completed and indeed FPL is enthused about the prospect of CWM being implemented as a demonstration fuel in one of our 400 MW units to displace fuel oil. Preliminary study indicates that conversion of some FPL units to CWM could substantially reduce oil consumption and save our customers money, if our present projections of fuel costs and conversion economics prove accurate. FPL has also drawn the following conlusions from its CWM investigation to date:

1) CWM fuels are readily combustible.
2) CWM fuels can be produced which exhibit acceptable handling and storage properties.
3) No significant advances in hardware technology are needed to commercially produce CWM on a utility scale.
4) Further testing, analyses and a large scale demonstration of CWM fuel in an oil-operated utility boiler is needed to resolve all technical and economic issues.

I would assess FPL's level of confidence in the prospect of anticipated cost savings at something around 60-65%. No prudent utility could risk a multi-hundred million dollar conversion to a "new" fuel with a level of confidence in that range. Therefore, in recent weeks, FPL's management made a commitment to attempt to raise this level of confidence to something like

90-95% by authorizing an ambitious scope of work described earlier as Phase 2. Phase 2 will require 12 months and an estimated expense of up to $1.5 MM. It is anticipated that other interested parties will contribute services, time, and funds to assist in this advanced scope of work.

During Phase II we intend to conduct an independently witnessed comparative test program among those entities considered to be willing and capable prospective CWM processors. From this we hope to learn the inherent yields of these processes, the cost of the processes using three different coals, the ultimate cost of CWM fuels delivered to FPL, the prospects for scaling up to commercial operations, and what sensitivites exist in the various processes. We will focus extensively on the modifications needed at FPL facilities in order to receive, store, transport, and burn CWM; as well as the equipment considerations for ash disposal, other fuel related and environmental implications, such as particulate or sulfur control. We will learn more about the trade-offs between fuel specs, fuel cost, plant modifications, and unit operation conditions.

Hopefully, Phase II will produce a viable business approach to CWM, as a result of discussions among those who propose to participate in the CWM industry. It will also permit development of plans and schedules for FPL's use of CWM, both at a demonstration level and as a permanent conversion fuel. Most importantly, this Phase 2 work is intended to give us the detailed technical and economic information we need to decide whether to proceed with a full scale test of CWM in one of FPL's large power plants.

Without prejudicing the Phase 2 initiative, FPL believes there must be a clear and confident indication that CWM can be procured, long-term, at savings levels of $2.00 - $2.50 per MM Btu as compared to fuel oil. This level of savings would permit FPL to justify the plant conversions anticipated to accommodate CWM, with some net cost benefit for our customers.

Cost estimates from the more prominent and prospective CWM processors reveal that our required savings levels are not unrealistic. Some processors are boasting of $3.00 - $3.25 per MM Btu in 1983 dollars when they achieve CWM commercial status. We have tried to temper their optimism in our own estimates, but we are encouraged by the economics they suggest when compared to our oil price scenarios.

Another tempering factor which we have some difficulty assessing at this time is the phenomenon of acid rain, and the proposed legislative actions to alleviate its affects. Simply stated, any legislation which would require FPL to indiscriminately or unnecessarily retrofit our 400 MW units with flue gas disulfurization apparatus would, in all likelihood, destroy any economic incentive we might have to convert those oil-designed units to CWM or any other coal-derived fuel. The additional cost of scrubbers compounded by the fewer years of useful life of these units would skew the total costs such that coal-derived fuels would be rejected in favor of continued oil use.

In summary, FPL views coal-derived fuels as the pre-eminent alternative to oil in many of our oil-designed units. We have nine 400 MW units of the same basic design. In addition, we have four 800 MW units that have shown significant promise as conversion candidates in our CWM studies to date. For Phase 1, our base case assumed conversion of two 400 MW units and two 800 MW units -- 2,400 MW total. Over 5,000,000 tons of coal would be consumed annually by FPL in this base case. One can easily see that oil-designed units converting to coal or coal-derived fuels represents a potential market without equal in these days of slowed utility expansions.

FPL applauds the endeavors of this Senate Subcommittee for focusing on issues relative to increased coal utilization, and we pledge to continue our look to coal as an alternative to the OPEC stranglehold.

Senator **WARNER**. I would hope to put in the record the resources of water will likely be needed for this expanded production of coal and some of the plant. Mr. Henderson, are you still here? Some mention of the plant up around the Rappahannock, when I drove up over the Rappahannock the other day, she was practically dry.

Mr. **HENDERSON**. Well, we use a pond that empties into the Rappahannock and there's a 2,000-year supply of water. Quite frankly, coal-water mixtures don't use much water.

Senator **WARNER**. Twenty-nine percent. So what you do is, you supply your own independent water source, independent of whatever the community has in streams, and so forth?

Mr. **HENDERSON**. Yes.

Senator **WARNER**. I see, thank you.

Mr. **HOCH**. Senator, I'll be glad to get some information ready for the record.

Senator **WARNER**. That would be helpful as would Mr. Henderson putting a little insert into the record on that.

STATEMENT OF DR. WILLIAM B. HARRISON, SENIOR VICE PRESIDENT, SOUTHERN COMPANY SERVICES, INC.

Dr. **HARRISON**. Thank you, sir. I am William B. Harrison, senior vice president of Southern Company Services. Our company is part of the Southern Co. System which also includes Alabama Power, Mississippi Power, Georgia Power, and Sothern Electric International Power. Our system operates something like 25,000-megawatts capacity, most of which is coal fired. In that sense, the perspective I give you is little different from those of the other panelists at this session. Roughly 80 percent of our generation is coal fired. It has been, historically, and we expect that it will continue to be as we look to the future. We do have nuclear facilities, both existing and under construction, but our future growth is clearly dominated by coal as the principal fuel. I would also like to point out that our company has a strong tradition in technological development. In the past 10 years, we've been involved with five different flue gas desulfurization systems on a plant-size scale for cleaning up combustion gases. We've been involved for 10 years in the management of a pilot plant for the sulfur refining of coal which, I am happy to say, is cosponsored by the Department of Energy and the Electric Power Research Institute. And I will allude to this briefly again in a moment. We are currently operating bag-house facilities to get small particulate matter from combustion gas with high sulfur eastern coal and we are quite active in exploring the science of what is now being called limestone injection of multistage burners [LIMB] technology, but which we prefer to call viable sulfur emissions control [VSEC]. My point is, we are committed to coal, we are committed to the new technologies. I wish to offer a slightly different perspective, however, when we address the question of how do we build future coal markets? Within our own company and those that are dominantly burning coal the development of new technology isn't so much to increase the market share of coal in our business. We are committed to coal, we don't really have any other game to play as we look to the future. So the way I see new technology and its role in our type of company is to improve the economic or environmental or other basis on which we build future generating facilities. There will be some retrofit of existing plants, its true, but we are not as concerned as some of these others with respect to the very important issue of converting from oil to coal.

With this difference of perspective, then I would like to add a new dimension to the discussion. How do we build, not market share, but the market in coal? The way to do that is economic prosperity. So we ask, what can the Government do to improve the coal markets in a coal-burning utility company? Its to keep on doing those things that build a sound, well-founded, and advancing economy. And I'm sure you know the implications of that statement, Senator Warner. Let me go further, however. I would add that we were fully supported in these technologies because they will be competing with each other in order to move into the new generation marketplace.

There's another far more important aspect of building the coal markets then can be provided from within the utility industry. It has been alluded to already and I'm referring to the synfuels prospects. This addresses the transportation sector of our economy and it can be a vast marketplace for coal. And it is that opportunity that I wish to address very briefly. One might ask, what is the deterrent in the advancement of the synfuels industry today? Its clearly the uncertainty about the world oil market. But I believe that can be managed if we go ahead and develop an energy policy which addresses it. This has an impact on our industry, don't misunderstand me. We have been in synfuels development, as I said, for 10 years. Our original purpose was to develop a clean, solid fuel from which the mineral matter or ash, has been removed and most of the sulfur has been removed. We succeeded in doing that. We now advance the technology—we, in a generic sense—to the point where, through a two-stage liquid action, we can produce fuel that is fully refinable to transportation fuels. Now, the impact on our industry is that it will create a whole line of fuels from the solid, which is the least expensive coal-derived fuel that anybody can make, to liquids which are perhaps the most needed if, indeed, we decide to reduce our dependence on foreign oil. You might ask the question, Why are we concerned still about the dependence on foreign oil because its been declining since 1980? Well, the reason is that we're still as dependent on foreign oil now as we were in 1973. And we can all remember the impact of a sudden disruption in that oil supply. If anything, its clear that the region from which we get that oil is less stable now, not more stable, then it was at that time. So there is still a security risk that must be addressed. In my own opinion, the security risk is sufficient to do something about sunfuels prospects for our future. In addition, there is the economic risk. We're still spending over $60 billion a year for foreign oil. In the 1980-81 region it was over $80 billion. You don't have to keep that up for many years to create the cash equivalent to the national debt or the cash equivalent to the top 500 U.S. corporations, all spent for buying foreign oil which we do not need to burn. My strategy, which I would respectfully request you to consider, sir, is for the United States to go ahead and announce a firm policy to diminish our dependence on foreign oil on a regular basis, so much per year, until we're down in the 5-percent range where we could handle it if its suddently disrupted. If its done over a period of 8 to 10 years, this find of strategy woudn't create any major economic disruptions in our domestic energy marketplace. It would create the incentive for private venture capital to go on into the synfuels market. Now as I say, my outlook of how to build major new markets for coals is very simple. It has these two parts: Build a strong U.S. economy which helps the energy marketplace and, hence, helps coal; and diminish our dependence on foreign oil which eliminates a security risk, it will eliminate the economic risk, it will build jobs at home. I don't see anything but good coming out of that kind of policy.

My closing statement is in reference to the discussion we've had about acid rain. I think you should know that the Edison Electric Institute is just on the verge of releasing what is their best effort and a statement explaining the rationale for the electric utility industry's position on acid rain legislation. Mr. Kaslow and I have been privileged to work in the drafting of that instrument and, if I may, I'd like to be sure that you and the members of your committee receive copies as soon as it can be made available to you. Thank you for the privilège of presenting my views for the panel. I must apologize to you and the others. I must leave because of time commitment.

[The prepared statement of Dr. Harrison follows:]

Statement of Dr. William B. Harrison
before the Field Hearing on
"Enhanced Coal Technology - Coal's Market for the 80s"
U. S. Senate Subcommittee on Energy and Mineral Resources
Blacksburg, Virginia
August 9, 1983

I am William B. Harrison, Senior Vice President of Southern Company Services, Inc., of Birmingham, Alabama. Southern Company Services is affiliated with Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Electric International to comprise The Southern Company system. As suggested by the names of the affiliated companies, the Southern system provides electricity to customers in four states of the Southeast. Electric generation in this system is based primarily on coal, and the historic tradition of strong dependence on coal is expected to continue far into the foreseeable future. At present, approximately 80 percent of the system's electricity is generated from coal, requiring purchases in the range of 30 to 35 million tons per year over the last few years. The subject of this hearing, which I understand to be the prospect of enhancing future markets for coal through new technology, requires some interpretation for a largely coal-burning system such as ours.

First, I should say that our system has a strong tradition in technology development related to the use of coal in power generation. Over the past ten years, we have been actively involved in the development of five different flue gas desulfurization systems; we have operated a pilot plant for solvent refining of coal and are now able to produce either solid or liquid boiler fuels as well as liquids which can be further refined to transportation fuels; we are currently active in the development of baghouse filtering systems to collect fine particulate matter in the combustion gases emitted from our power plant operations; and we are on the forefront of the promising new technology referred to as Lime Injection Multistage Burner which we prefer to call Dry Sorbent Emission Control. Thus, we have a commitment to coal technologies and extensive experience in developing and utilizing such technologies.

As we look to the future, it is important to distinguish between market share and total markets for coal. Since our system already is strongly dependent on coal, the new technologies are not likely to increase market share in comparison with other energy resources that we use to make electricity. In our system, new technologies will compete with each other on the basis of which can enable us to offer to our customers electricity at least cost, using the coal resources which are available to us. One might ask then how can total markets for coal be increased if new technologies are not able to create increases in market share. My answer to that question is simply that the way to increase coal markets in our company is to increase demand for electricity.

The Honorable Donald P. Hodel, Secretary of the Department of Energy, in his recent address before the Edison Electric Institute, reaffirmed his own conviction that, though the correlation between gross national product and total energy requirements has become highly uncertain in recent years, the correlation between gross national product and electric energy demand has remained strong. He stated that he expects growth in demand for electricity to be at least equal to, and perhaps in excess of, growth in the economy through the year 2000. Thus, the prosperity of this nation will create greater demand for electricity which, in turn, is guaranteed to create greater demand for coal in systems like ours.

As we then turn to what the government can do in order to assure this continued growth in gross national product, we get into other areas related to reducing the national debt, control of inflation and recession, and other topics with which this Subcommittee is familiar. In brief, what is good for the nation's economy is good for the coal industry.

It is obvious that some electric utility companies, less dependent on coal, are faced with much different problems related to conversions from oil and gas to coal. Such conversions would create increases in market share for coal in those companies.

Another factor is the threat of acid rain control legislation which, if passed, could require changes in the technology for burning coal in existing power plants. Our industry organization, the Edison Electric Institute, and our system have gone on record in opposition to such legislation. (A copy of the EEI position statement is attached.) We feel that any legislation is premature in light of recent publications from the National Academy of Sciences and other sources which make it clear that the premises on which the current legislative initiatives are based presently cannot be supported with scientific facts. If such legislation is enacted, we do not anticipate that it will create new total markets for coal, but it may shift very drastically the market from high sulfur coal to low sulfur coal in the electric utility industry. In fact, such legislation may well create disincentives for conversion from oil and gas to coal, and, conceivably, could create conversions from coal back to oil.

Now let us consider another avenue of growth for the coal industry based on new technology - synthetic fuels. The potential in the synthetic fuels market is as large as, and perhaps larger than, the total market for coal which now exists for the electric utility industry. Clearly, the development of a viable synthetic fuels industry will have impacts on electric utilities by making coal-derived fuels available to them in a variety of forms. But of even greater importance in terms of fuel markets is the potential for factoring coal-derived synthetic fuels into the transportation sector. One might question how this synthetic fuels market can be stimulated in the light of the current world oversupply of oil and the general softening of market prices which has taken place in the past year. There is no doubt that the prospects for synthetic fuels are keyed to the world energy market and the need for certain provisions in national energy policy. Though our national dependence on foreign oil has declined significantly from its peak years of 1977-1979, we are still practically as dependent on foreign oil now as we were at the time of the 1973-74 embargo. Many of the articles I read on the energy outlook suggest that the U. S. demand for foreign oil has now bottomed out and that we can expect increases for the next several years. Therefore, one point I wish to make is that there is still a national security risk related to dependence on foreign oil. Many of us can vividly recall the days of the 1973-74 embargo and the quickness with which that only partially effective embargo created serious social impacts in the United States. If anything, I conclude that the Middle East is less stable and the security risk is even higher now than it was then. As recently as late 1982, the International Energy Agency, the Cambridge Energy Research Associates, and Dr. James Schlesinger, former Secretary of the Department of Energy, among others, issued statements which warned of the likelihood of another oil crisis before the end of this decade. It appears to me that the only practical strategy to protect the United States from serious repercussions of another oil crisis is to build a synfuels industry based on coal.

Another aspect of this dependence on foreign oil is financial in nature. As we all know, the national annual financial commitment for foreign oil rose rapidly during the 1970s until it peaked in 1981 at over $80 billion. Last year, due to the reductions in demand and also reductions in unit price, the price tag for imports was slightly over $60 billion, which is still a very significant outflow of dollars for our economy to sustain. Many financial experts attribute the recent worldwide recession largely to the oil price shock of the 1970s. There is no doubt that, if not the sole reason, it was a major factor. Here again, it is clear that the practical strategy to reduce tnis large outflow of dollars is to divert them to building a domestic synfuels industry based on coal. The technologies for processing coal have been advanced significantly over the past ten years or so in a number of pilot plants and demonstration projects. It is technically feasible to produce a wide range of products - gases, liquids, and solids - also in a range of qualities and prices. The unresolved problem for the synfuel industry is not technology - it is the market uncertainty which accompanies our current energy policy.

In order to stimulate growth of the synfuels industry, I believe it will be necessary for our government to make a change in energy policy, directed at reducing our dependence on foreign oil. I believe the desired result could be achieved by implementing a policy of reducing this dependence on imports by specific amounts each year for the next eight to ten years, with the ultimate goal of reducing dependence to less than five percent of our total oil requirements. I believe that this would create the incentive for private capital to create commercial synthetic fuels production capacity. By stretching out this reduction of dependence on foreign oil over several years, there would be very little impact on society and the net effect would be to keep in the United States the dollars and, indirectly, the jobs which heretofore have been exported on a grand scale. While expanding the coal market as a result of this strategy, we also would achieve the beneficial results of eliminating both the economic and the security risks which accompany our current dependence on imports.

In summary, the formula I wish to advance for consideration of the Subcommittee is very simple. In order to strengthen the future markets for coal, we must continue to strengthen the U. S. economy and we must reduce our dependence on foreign oil. These two steps would assure prosperity and growth in the coal industry for the long term.

The Edison Electric Institute Position
On Acid Rain Control Legislation

August 15, 1983

Introduction - The Edison Electric Institute has been supporting the position that (a) not enough presently is known about acid rain to adopt a control program; (b) more research is needed to assure the effectiveness of any measures that may be taken; and (c) there is no basis for the urgency which characterizes several current legislative proposals for further emission reductions.

The Edison Electric Institute has rigorously reexamined its position regarding acid rain control legislation and has concluded that there is insufficient justification to alter its position. The Institute continues to believe that the imposition of emission reductions would be premature, in light of persuasive evidence that there is little probability of achieving the desired environmental improvement, notwithstanding the substantial economic burden that would be entailed.

The industry continues to believe, based on its own research and on information contained in the recent National Academy of Sciences report (1)*, that the prudent course of action would be to continue with intensified research to define clearly the acid rain phenomenon and to determine the appropriate control program, if found to be necessary, prior to enacting legislation. Meanwhile, there are ways to mitigate lake acidification in sensitive areas, if there is sufficient justification to do so.

This position was reached after prolonged review and discussion of the present state of scientific knowledge on the subject. The political and emotional aura surrounding this issue has not gone unnoticed. However, the industry has an obligation to those it serves to rise above these pressures and continue to base its policies and recommendations on facts and good judgment.

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*Numbers in parentheses refer to references in the Bibliography.

This document records the basis for the Edison Electric Institute position. It should be borne in mind that the electric utility industry, through the Electric Power Research Institute (EPRI), already has conducted major studies and intends to expand its efforts in relevant science and technology: causes and effects of acid rain; causes of lake acidification; relative impacts of local and distant acid rain precursors; and technology for abatement of acid rain precursors, should additional controls prove to be warranted. The currently planned five-year program (1984-1988) of EPRI includes a total of $476 million for programs relevant to this issue, $175 million of which directly addresses the unresolved scientific and technical questions which must be answered in order to develop a rational control program. EPRI efforts are undertaken by some of the most capable and credible investigators in the technical and scientific community. The quality and scope of this program, the largest in the world on acid rain science and technology, sets the electric utility industry apart from those who are attempting, through allegations which have little basis in fact, to gain public support for urgent and sweeping legislative remedies for the acid rain "problem."

The Acid Rain "Problem" Is Much Discussed But Poorly Defined

There is a basic fact upon which all parties to the acid rain debate agree: some lakes in sensitive regions in northeastern U. S. and eastern Canada are too acidic to support desirable fish populations. Simplistic assumptions have been made and widely disseminated to the effect that lakes are acidic because of acidic precipitation and that reducing acid precursors in the atmosphere will solve the lake acidification problem. Ignored is the basic fact that many of these lakes were known to be acidic long before the major urban growth in the Northeast or the industrial growth of the Midwest. Ignored is the fact that lake acidity is influenced far less by inputs of acidity from precipitation than by the high acidity naturally found in forest litter (2) or in wetlands (3) or by the natural buffering capacity (or lack thereof) in the soils found in the watersheds for these lakes (4).

There is another popular misconception concerning precipitation which suggests that any deviation from a fixed point of "normal" acidity may be explained by emissions from burning fuels, and that all such emissions cause acid rain and, therefore, necessarily must be "bad." The facts reveal that there is no fixed "normal" acidity, that practically all rain is acidic, and that normal acidities cover a fairly broad range, even in remote places of the world little affected by fuel burning, urbanization, or industrial activity (5, 6).

The assumption that sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) are major precursors of acid rain is not being challenged. However, there are many sources of these gases in the atmosphere other than, or in addition to, electric utilities; and there are other chemical substances in the atmosphere which control the pathways by which these gases react to become acids (7). The simplistic perceptions which focus attention on electric utilities generally ignore other sources of SO_2 and NO_x, such as private homes, automobiles, factories, etc. In addition, the surge of interest in acid rain has mistakenly, or only speculatively, attributed to acid rain many effects (public health, building deterioration, crop damage, etc.) which properly should be attributed to other causes.

Thus, many fundamental gaps remain in defining the acid rain problem. It is essential that the problem be defined before an effective solution can be devised. Yet, current legislative proposals appear to be competing for acceptance of differing solutions to a problem which has not been defined.

Alleged Effects Of Acid Rain Are Unproven

The fact that some lakes are acidic is not being debated. It is important to recognize the factors other than acid rain which contribute to acidification of lakes and streams (4, 8). The Institute is aware of studies showing increases in lake acidity in recent years. On the other hand, a study of 188 lakes in 22 states, including continuous monitoring data over a period of ten years or more, showed 71 lakes with decreasing acidity and only 18 with increasing acidity (9). Sediment cores from acid lakes indicate that many of them became acidic thousands of years ago (10).

In connection with allegations of forest damage, although effects have been observed in laboratory studies using simulated rain with acidities higher than encountered in the natural environment (11, 12), field studies have not shown damage from acid deposition (13).

Other allegations of effects of acid deposition are widely disseminated, but factual confirmation is either indirect or nonexistent.

Source/Receptor Relationships Are Unclear

Even accepting the fact that SO_2 and NO_x from all sources, natural and man-made, are major precursors of acids in precipitation, a number of very basic relationships still remain unclear. There are questions about the rates of reaction, the need for catalysts in the reactions, the form and mix of reaction products, etc. There are conflicting and confusing data on the rates at which SO_2 reacts to form sulfate ions (SO_4) and the degree to which the amount of sulfate ions can be regarded as a measure of acidic input. Obviously, sulfate ions can react with hydrogen ions to form sulfuric acid, but they also can react with other ions to form compounds which are not acidic (14, 15). Hence, sulfates are not necessarily appropriate measures, or surrogates, for acidity.

Other areas of uncertainty relate to quantification of natural sources of acid precursors in addition to man-made sources. An example may be found in studies which estimate the generation of NO_x by lightning (16), revealing it to be a source too large to be ignored.

Still another unresolved issue relates to the relative contributions of local and distant sources to specific receptor areas (17). Implicit in this issue is the development and verification of models which realistically relate deposition rates to source strength, distance, wind rose data, and emission chemistry and transformation. While the attention of most investigations to date has been on utility sources, pursuit of source/receptor relationships must also include the deposition effects of non-utility sources of NO_x and SO_2, and combinations of these and other reactants which are found in urban plumes or elsewhere. The National Academy of Sciences report (1) addresses this issue in this way:

"The actual limitations of predictive models for calculating the effects of sources on sulfate deposition are not well defined because of deficiencies in knowledge of atmospheric processes and the lack of coherent regional data on air quality and deposition. No studies of the validity or limitations of models for nitrate concentrations have been performed. No model for wet deposition of acidity has been developed that takes account of sources and distributions of all the important ions in precipitation."

The Sense Of Urgency Cannot Be Justified By Facts

The public is being told that immediate countermeasures are needed in order to avoid environmental catastrophe from acid rain. Available data do not confirm this. Earlier reports on rapidly increasing acidity across North America no longer are considered to be accurate (19). Good monitoring data for establishing trends have become available only during the last decade (13, 19). The Hubbard Brook, N. H., data cited in the recent National Academy of Sciences report show that, if there is a detectable trend in acidity over the years 1965-1981, it is slightly downward (1). The Integrated Lake Watershed Assessment Study of EPRI has shown no change in average acidity in three lakes being studied in the Adirondacks over the last five years (4). The same study developed a model explaining marked differences in the acidity levels of these lakes, all of which were subject to essentially the same precipitation. Using the model, it was shown that either doubling or reducing by half the atmospheric input of sulfur would not produce a meaningful change in lake acidity.

The conclusion drawn here is that there is time to gather enough information to determine whether (a) there is a problem which demands a solution, (b) there are solutions which can be implemented, and (c) the particular solution(s) to be implemented will be cost-effective and in the public interest. Until these conditions are met, even minimal interim control measures are not justified.

Current Legislative Proposals Are Severely Flawed

To varying degrees, all of the proposed bills for acid rain control legislation purport to protect the northeastern U. S. and eastern Canada from further "damages" from acid rain, and it is presumed that this is the basic objective. Though proposals differ in the extent of control to be achieved, they have in common the assumption that the most effective way to protect lakes in the sensitive areas of the Northeast is to limit emissions of SO_2 from power plants in the Midwest. The evidence cited above and other evidence in the NAS report (1) identify some of the major deficiencies of this legislative strategy. It is clear that the lake-acidification process is more sensitive to terrestrial influences in the local area than to atmospheric influences, wherever they originate (21). It is also clear that many sources of SO_2, other than power plants, and all sources of NO_x and other constituents of urban plumes are being ignored.

It is significant that most legislative proposals for protecting the sensitive area of the Northeast have not taken into account serious efforts to estimate the change in acidity of precipitation which can be expected from the proposed emission reductions. Of special importance is the work at the Energy Laboratory of Massachusetts Institute of Technology (18), which shows precipitation acidity to be very insensitive to control by emission reductions. This work addresses a basic factor in the legislative strategy, and it deserves careful evaluation in the process of developing national commitments to acid rain control.

An additional point which seems to be overlooked is that emissions from electric utilities are destined to decline in the future as existing plants are replaced with new sources, including coal-fired sources subject to New Source Performance Standards, and nuclear facilities. In some areas of the country, including the Northeast, there has been a significant decline in SO_2 emissions as a result of compliance with the Clean Air Act amendments of 1970 and 1977. Of special interest in connection with proposed legislation is the fact that the investor-owned utilities in Illinois, Michigan, Indiana, Ohio, Kentucky, and West Virginia, along with the Tennessee Valley Authority, effected an actual 2-1/2 million ton reduction in annual SO_2 emissions over the years from 1975 through 1982. Five acid-precipitation monitoring stations, operated from 1979 through 1982 in Ohio, Massachusetts, North Carolina, and Indiana, have shown no difference in acidity of rainfall as a result of this change in emissions. Though further analysis is needed, sufficient data are available to justify skepticism about the effectiveness or usefulness of further emission reduction proposals at this time.

Still another consideration is the cost of proposed legislation. A recent analysis of data from 24 utility companies revealed that the costs required by the emission control strategy proposed in S.768 would involve $15 billion in capital costs and $4 billion in annualized costs (20). These companies comprise less than half of the total generation in the region affected by the legislation, and would be responsible for only 3.6 of the 8-million-ton SO_2 reduction that would be mandated in the bill. As stated earlier, a rational plan of acid rain control must await the necessary information to show that legislative proposals address real problems with strategies judged to be effective and at costs commensurate with the benefits. Otherwise a grave injustice will have been done to an unsuspecting and trusting public.

Critical to any discussion of emissions control is a clear definition of what is to be achieved. Specifically, the answers to two questions are needed. First, what is to be reduced if SO_2 emissions are controlled: acidity of precipitation, total sulfate deposition, total sulfur deposition, ambient particulate sulfate, or total atmospheric sulfur? These five are not entirely mutually exclusive but some degree of exclusivity does exist among them. If a scientific or intellectual rationale exists for reducing any or all of them, a second question is: where should these reductions take place - in specific sensitive regions, over the eastern part of the country, or over the entire (lower 48) United States? The answers to these two questions have an all-important bearing on any discussion of control strategy.

The Program Ahead - Toward A Rational Solution

The Electric Power Research Institute is making a significant investment in efforts to define the acid rain problem, to understand the science relevant to the problem, and to develop technical alternatives for responses if needed by the electric utility industry. The program of work is planned in the context of the National Acid Precipitation Assessment Plan. Among the leadership of these programs, there already is in effect a spirit of cooperation and mutual respect, as well as the seriousness of purpose which accompanies work of national significance. As noted earlier, the EPRI five-year program (1984-1988) involves commitments of $476 million toward generally relevant subject areas, $175 million of which is to be devoted directly to studies of the ecological effects of acid rain, and to work on atmospheric physics and chemistry. No other party to the acid rain debate can offer so much objective, scientifically and technically valid information to be used in resolving this matter, other than, perhaps, laboratories of the Federal government. Some of the excellent work by EPRI, in the areas of atmospheric chemistry and ecology, has been referenced in the recent report by the National Academy of Sciences (1).

The most important aspect of the current planning is to identify expected milestones and to understand how to characterize environmental risks which prevail in various watersheds in sensitive areas.

Summary

The fact that certain lakes in sensitive areas are acidic is the starting point for the acid rain debate. The first error of popular belief is that lake acidification is a recent phenomenon caused by acid rain. A study of the natural history of lake acidification reveals that this is not so. The second error of popular belief is that the dominant contributor to lake acidification in the Northeast is SO_2. Data obtained in the Northeast do not confirm this. The third error is that the location of sources of SO_2 which contribute most to acid rain in the Northeast can be traced to specific regions. The National Academy of Sciences report explains that the connection between sources and receptors cannot be made with presently known facts. The final error is that the "acid rain problem" is caused by coal-burning electric utilities and that it will go away if drastic emission controls are implemented. The problem is lake acidification, not acid rain, and best estimates are that nature provides far more control of lake acidification than can be achieved by eliminating all utility emissions.

In exploiting the misconceptions noted here, public and political perceptions have been managed in a way that focuses attention on sulfur emissions and sulfate deposition, while ignoring the basic problem of acidification of the lakes. Most legislative proposals for acid rain control have been justified by concern for the lakes, but proposed solutions cannot be effective and are only partially relevant to the problem. In opposing these legislative proposals, the electric utility industry is protecting its customers (in effect, all citizens) from wasteful and ineffective programs which cannot produce benefits commensurate with their costs. Cost sharing and taxing schemes have been advanced to make various proposals more palatable, but, regardless of who pays what portion of the total bill, these proposals cannot constitute sound social investments so long as commensurate benefits cannot be expected.

Through its prior efforts and its announced plans, the electric utility industry is taking a responsible role in developing an understanding of the acid rain issue and the technology to implement countermeasures if needed. The industry is working diligently and cooperatively with other responsible parties, including government laboratories.

The Institute believes that it is dealing with the most credible information currently available and that its interpretation of this information is strongly substantiated by information in the recent National Academy of Sciences report. It is hoped that reason and intellectual honesty can be more strongly emphasized as the acid rain debate continues and that the public can be shown the important investigations being undertaken by the electric utility industry. The Institute intends to be fully responsive as new information is gathered and will reevaluate its position from time to time as appropriate.

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Senator WARNER. Thank you very much for coming and we appreciate your testimony.

Now, sir, are you going to talk about your ship?

Mr. KASLOW. Yes; among other things, Senator.

Senator WARNER. That's fine. I think you should know that yesterday the first American ship to be both fueled by coal and transporting coal left Hampton Roads. Congratulations.

STATEMENT OF JOHN F. KASLOW, SENIOR VICE PRESIDENT, NEW ENGLAND ELECTRIC SYSTEM

Mr. KASLOW. Thank you, Senator. The comments Bill Harrison made before me on our 1973 dependence on oil hit us in spades in the Northeast since we were one of the first companies and one of the first regions to feel that effect. Whenever we report that in 1979, 78 percent of our electric system energy production was generated from oil burning with the balance by nuclear and hydro and we shifted to a much better balance in our view in 1983 when we expect coal will produce greater than 50 percent of our energy and oil only 20 percent. The shift to coal has not come easily or inexpensively. I mentioned that the problem started in 1973, but we weren't able to get permissions and approvals to do all our coal conversions until 1979. In any event, despite the slow approvals and spending close to $300 million to get 6 units coverted to coal, we think it was really worth the cost and the effort. Thanks to today's coal technology, our conversion has been most successful from both an economic standpoint and an environmental standpoint. And I'd just like to read off some numbers from a scorecard which I think illustrates that point. Our fuel cost savings to date, and this is in a period of a little over 2 years, fuel cost savings over $200 million. The net savings to our customers, after we paid the mortgage on the borrowed money that it took to do the conversion, about $90 million. Foreign oil displaced, over 22 million barrels and that's about $550 million in dollars that stay here rather than flow to foreign countries. Domestic coal burned, over 5.5 million tons. Sulfur dioxide emissions, 20 percent lower than when we were burning oil. Particulate emissions, 50 percent lower than when we were burning oil, and that's a rather shocking number.

While the net savings to our customers, and a greatly reduced dependence on foreign oil, reflect the achievement of two of our principal goals, the outstanding environmental results are worth emphasizing. Coal gets a bad rap nationally and it had been in our region as a dirty fuel, but I think our experience has helped to change some thinking on that. We are now burning in excess of 3 million tons of coal per year and are emitting less sulfur dioxide and particulates than when we burned oil. And even then, when we were burning oil, we were meeting our State implementation plan limits and were meeting the Federal ambient standards with a considerable margin to spare. So we think we were good on oil, but even better on coal.

Since the focus of this hearing is enhanced coal technology, I would like to comment on revisiting an old technology, and the Senator referred to that just a few moments ago. Within the past month one of our subsidiary companies commissioned a new coal-fired, self-discharging, coal collier which will transport coal from mid-Atlantic ports to our New England stations. In fact, that coal collier received its first load of coal yesterday and is now on its way to our station with 34,000 tons of Appalachian coal. The ship is appropriately named the *Energy Independence* and will deliver about 36,000 tons of coal mined in southern Virginia, northern West Virginia and Pennsylvania every 5 or 6 days. Beyond delivering 2.4 million tons of coal per year, the ship is powered by a coal-fired steam plant burning an additional 15,000 tons of coal a year.

Senator **Warner**. May I ask, what percentage of your needs are transported by that ship and if you are intending to acquire other ships if this one proves cost effective?

Mr. **Kaslow**. Our total coal burn right now, Senator, is estimated at a little over 3 million tons a year and this ship will carry about 2.4 million of that total, so we don't have enough for a second ship. But if we can find some people interested in our delivering coal in New England and if we can convert a few more units we may find the need.

As I mentioned, the ship will burn 15,000 tons of coal and its the first coal-fired ship built in the United States in the last 50 years. We certainly hope the good economy and good performance will make it the first of several coal-fired ships to be put in service in this country.

Clearly, we have made a major commitment to coal burning and we are pleased with the commitment. As we look to the future, both in our own company and in New England, we see that coal is going to be the dominant energy source for utility generation, both in New England and nationally. We think that enhanced coal technology is essential to ensuring that coal does, indeed, maintain its role as the leading producer of electric energy and that it remains the dominant fuel in the years ahead. The 1979 Clean Act amendments mandate stringent emission requirements for new plants and the current acid rain controversy is likely to add to those requirements. While some progress has been made in flue gas desulfurization, the use of flue gas scrubbers is not a very attractive option for the long run, in our view. There must be more viable options for both new plants and for existing plants for removal of sulfur dioxide and nitrogen oxides.

While the development of better coal-related technologies may provide expanded options for the future, we are very very concerned about the short-term impact of acid rain legislation. Particularly as a company which has just spent $300 million to convert plants from oil to coal. Some of the bills that have been proposed have nuances that could be disastrous to utilities. Bills, for example, that prohibit any increase in nitrous oxide emissions coupled with large sulfur dioxide emission requirements could actually put us back on oil which would be one of the most foolish things that could happen. That is one of the extreme bills. But there are gradations in the bills that have been filed and, as I say, one has to read very closely because there are nuances in many of those bills which has a tremendous impact in one or more cases. If an emission reduction plant for acid rain control is ultimately legislated by the Congress, it must recognize that the ability to cope with significant emission reductions, in an economically feasible fashion, should be scheduled in a way that permits enhanced technology to contribute to the program. We think there are things being developed that just have to be in place if there is going to be any significant end and should be a vital energy source for generations to come. Thank you very much.

[The prepared statement of Mr. Kaslow follows:]

Statement of John F. Kaslow
Sr. Vice President - New England Electric System

Before

Senate Energy and Natural Resources Committee
Subcommittee on Energy and Mineral Resources
Blacksburg, Virginia

August 9, 1983

Good morning. My name is John F. Kaslow and I am a Sr. Vice President of the New England Electric System and President of the System's wholesale production and transmission subsidiary, the New England Power Company. It is a pleasure to participate in this hearing on Coal Technology today - particularly since it is being conducted in a region of the country from which our company procures a significant share of its coal.

It may seem strange for a New Englander to be testifying on the subject of coal and coal technology. Just a few years ago our company - and New England as a whole - relied heavily on residual fuel oil. That picture has changed dramatically for the New England Electric System Companies. In 1979, 78% of our energy production was generated from oil burning - with the balance nuclear and hydro. In 1983 we expect that coal will produce greater than 50% of our energy and oil only 20%.

Our shift to coal has not come easily or inexpensively. Securing the necessary approvals to convert from oil to coal spanned a period of close to four years. Converting six generating units - three of which are completed with three in the process of final conversion - will cost close to 300 million dollars.

Was it worth the cost and the effort? Thanks to today's coal technology, our conversion has been most successful from both an economic and an environmental viewpoint. If we look at the following scorecard, it is evident why we believe it is a success:

Fuel Cost Savings to Date:	Over $200 million
Net Savings to our Customers to Date:	Approx. $90 million
Foreign Oil Displaced:	Over 22 million barrels
Domestic Coal Burned:	Over 5.5 million tons
Sulfur Dioxide Emissions:	20% lower than oil firing
* Particulate Emissions:	50% lower than oil firing

* (For units on which coal conversion has been completed.)

While the net savings to our customers - and greatly reduced dependence on foreign oil - reflect the achievement of two of our principal goals, the outstanding environmental results are worth emphasizing. We are now burning in excess of 3 million tons of coal per year and are emitting less sulfur dioxide and particulates than when we burned oil - and, even then, we were meeting our State Implementation Plan limits and were meeting the Federal ambient standards with a large margin to spare. From an emissions viewpoint, we were good on oil - but even better on coal.

Since the focus of this hearing is enhanced coal technology, I would like to comment on the rebirth of an old technology which underscores our company's commitment to coal burning. Within the past month a New England Electric subsidiary company commissioned a new coal fired, self-discharging, coal collier which will transport coal from mid-Atlantic ports to our coal burning stations. The ship, appropriately named the ENERGY INDEPENDENCE, will deliver approximately 36,000 tons of coal mined in Southern Virginia, Northern West Virginia and Pennsylvania every five or six days. Beyond delivering 2.4 million tons of coal per year, the ship is powered by a coal fired steam plant burning an additional 15,000 tons per year. This is the first coal fired vessel built in the United States in more than 50 years - and we hope good economy and good experience will encourage others to follow suit in the years ahead.

Clearly, the New England Power Company has made a major commitment to coal burning and we are pleased with our decision and our progress.

As we look to the future we are convinced that coal will continue to play a lead role in our energy future - both in New England and nationally. Enhanced coal burning technology is essential to reliance on coal as the dominant fossil fuel for power generation in the years ahead. The 1979 Clean Air Act

Amendments mandated stringent sulfur dioxide emission requirements for new sources. The current acid rain controversy is likely to add to the total emission reduction requirement over time. While some progress has been made in flue gas desulfurization, the use of flue gas scrubbers is not an attractive option for the long run. There must be more, viable options for new plants for both sulfur dioxide and nitrogen oxide removal if coal is to be a leading contender for new generating capacity.

While the development of better coal related technologies may provide expanded options for the future, we are concerned that potential acid rain legislation may pose serious problems for existing coal burners - where the control options are presently very limited. If an emission reduction plan for acid rain control is ultimately legislated by the Congress, it must recognize that the ability to cope with significant emission reductions - in an economically feasible fashion - should be scheduled in a way that permits enhanced technology to contribute to the program.

Coal can and should be a vital energy source for generations to come. Prudent technology development and sound public policy will strongly influence the outcome.

Senator **Warner**. Thank you, Mr. Kaslow.

STATEMENT OF DR. JAMES J. MARKOWSKY, MANAGER, ANALYTICAL AND RESEARCH AND DEVELOPMENT SECTION, AMERICAN ELECTRIC POWER SERVICE CORP.

Dr. **Markowsky**. I will adress the future technology that we, at AEP, have been pursuing. As you know, we are a large utility 22,000 megawatts installed and about 85 percent of our generation is from coal.

Mr. Chairman, the object of my presentation today is to outline American Electric Power's Pressurized Fluidized Bed Combustion Development Program. This is a privately funded development program and is being carried out in conjunction with STAL-LAVAL Turbin Co., a subsidiary of the Swedish manufacturer, ASEA; and Deutsche Babcock, a West German company.

Senator **Warner**. Where is this located?

Dr. **Markowsky**. Sir, we don't have a commerical plant operating. I will go into a compliment test facility that we have operating in Sweden. This is a development program initiated by American Electric Power about 6 years ago.

Senator **Warner**. I have left my notes in Washington on this subject, but there's one down here in the Kentucky area because I know there' movement in the Congress to raise some money for that one.

Dr. **Markowsky**. That's the atmospheric plant, I think.

Senator **Warner**. Your project?

Dr. **Markowsky**. Our project.

Senator **Warner**. I would appreciate your differentiating between the two approaches here.

Mr. **Markowsky**. Mr. Chairman, I propose to do that and I will show the difference between the two but pressurized fluid bed combustion is a relatively new technology, which AEP considers to be the most economic and environmentally compatible method for future generation of electricity.

Before I proceed with outlining AEP's PFBC development program, I first want to briefly describe the combustion process within atmospheric fluidized bed [AFBC], and pressurized fluidized bed combustion [PFBS]. In fluidized bed combustion, the sulfur in the coal is removed during the combustion process. We had discussion before about combustion. This is the sulfur removal during the combustion process. Crushed coal and a sulfur sorbent, like limestone or dolomite, are continuously injected into a vessel, where the coal is burned at a relatively low temperature while in contact with the sulfur sorbent. The air is fed in through the bottom of the bed giving rise to a turbulent coal and sorbent particle motion, which resembles a boiling fluid-like appearance.

Fluidized bed combustion can take place either at atmospheric pressure, as I have mentioned, or at elevated. The first slide will illustrate the difference. In AFBC, the steam is generated from inbed boiler tubes which is used to drive a conventional steam turbine. The combustion gases from the bed are cooled by water tubes about the bed.

In PFBC, the fluidized bed merges a gas turbine with a steam turbine in a combined cycle arrangement as shown in the next slide. The gas turbine portion of this cycle is driven by combustion gases from the fluidized bed, which have been cleaned by a series of cyclone dust separators. The gas turbine, in turn, drives both an air compressor, which provides combustion air to the fluidized bed; and a generator, which produces electric power.

Gases exhausting from the gas turbine still have considerable energy, which is used to preheat feedwater for the steam turbine cycle. This preheated feedwater is then sent to tubes within the fluidized bed, where conversion to steam takes place. The steam is used to drive a steam-turbine generator, producing additional electric power. The combined cycle nature of PFBC, pressurized fluidized bed combustion, results in a more efficient generation of electric power from high sulfur coal.

The ultimate goal of the AEP development program is the commercialization of the cycle shown in the next slide. This commercial cycle would incorporate a supercritical, single reheat steam cycle coupled to a gas turbine cycle. A commercial plant comprising one unit will have a gross electrical output of approximately 665 megawatts. Each gas turbine produces 75 megawatts for a total of 150 megawatts of gas turbine power. The balance, 515 megawatts, is produced by one steam turbine. The net efficiency is 40 percent.

Next, I will address the advantages of PFBC for electric power generation. These are the conventional pulverized coal power with wet limestone flue gas desulfurization. These advantages are summarized on the next slide. They are: Over 90 percent sulfur capture from high sulfur coal; modular plant design, which allows smaller plant sizes with minimal impact due to diseconomies of scale which is a very critical thing with the utilities with very uncertain load growths in the future; lower NO_x emission, practically one-third less compatible technology; fuel flexibility—not critical as to the heating content of the fuel; dry waste product, very critical instead of the wet sludge and approximately one-fifth less waste product also then the conventional plant with a scrubber; approximately 14 percent higher electrical generating efficiency; and also a lower capital cost of approximately 10 percent.

These potential advantages are the driving forces behind the AEP's development program, which I would now like to outline.

In December 1976, AEP, along with STAL-LAVAL, embarked on the first phase of the privately funded program, which was a 6 month feasibility study. The object of this study was to assess the technical and economic merits of PFBC. This was performed by developing a conceptual design of a 170 megawatt demonstration plant to be located at Brilliant, OH, at our Tidd facility. The results of the study were encouraging, and it was decided to continue the program.

The next three phases as outlined on that schedule—indicating slide projection—of our program entailed both pilot plant test work and engineering and design of the proposed 170 megawatt demonstration plant.

At the conclusion of these phases, over 2,000 hours of testing was completed using Ohio high sulfur coal and dolomite. All of the testing was performed at the pilot plant located at Leatherhead, England.

The test programs and design efforts were successful in substantiating the merits of PFBC technology, and it was decided to construct an intermediate size facility prior to construction of a demonstration plant.

In 1980, however, it became clear that the new administration was redirecting the Federal Government's role in energy development in that Federal funding would no longer be available for demonstration projects. This was a blow to our program as prior to this we had an ongoing dialog with the U.S. Department of Energy with respect to their cost sharing in the construction of the demonstration plant. Up to this point, DOE had participated in our program by partially funding some of the pilot plant test work. Although this was a disappointment, we decided to continue our development program.

The next phase of the program was intended to perform the detailed design of the 170 megawatt demonstration plant. In addition to the detailed design effort, a 15 megawatt—thermal—component test facility was constructed in Malmo, Sweden to operate on high-sulfur coal. The purpose of this facility was to verify, at reasonable cost, the operation and reliability of an integrated PFBC pilot system. An artist's rendering of the CTF is shown in the next slide. Just to give you an idea of the physical size, there is an individual located there and that vessel is 13 feet in diameter and over 40 feet tall. We have shipped 2,800 tons of Ohio and Indiana high-sulfur coal along with 1,400 tons of Ohio and Indiana dolomite to this facility.

The preoperational testing, and the test program currently planned will entail 2,000 hours of operation at this facility. To date, over 500 hours of operation have been accomplished.

Through 1982, $23.3 million has been spent in support of this program. AEP's portion has been $3.2 million, our European partner's portion has been $16.7 million, U.S. DOE's portion has been $2.6 million, and the remaining $800,000 from other interested parties.

Due to the anticipated funding difficulties, we are currently modifying the design of the demonstration plant to reduce its size from 170 MW to 64 MW. The cycle arrangement of the 64 MW Tidd Demonstration plant is shown in the next slide. An existing turbine at Tidd would operate at about half power with an output of 49.7 MW while the STAL-LAVAL GT 35 gas turbine output will be 14.2 MW. It is currently anticipated that the 64 MW demonstration plant will cost $110 million. Although the $110 million demonstration plant whose cycle is shown here is lower than the original design of the 170 MW plant, availability of funding support clouds AEP's ability to demonstrate this highly attractive technology.

The next slide presents a schedule for the 64 MW demonstration plant based on only technical constraits, given no financial constraints.

The current phase of the development program will entail both the operation of the CTF and completion of the preliminary design of the 64 MW demonstration plant by the end of 1984. Assuming the result from both efforts are positive and funding is available, construction could commence in 1986 with operation in 1988. If this schedule can be met, the first commercial size PFBC plant could be operating by the mid-1990's. It is apparent that the commercialization process is both long and costly, thus, beyond the financial means of private industry and especially a regulated electric utility. However, AEP and its partners are continuing to develop PFBC and will be in a position to assess the technological readiness for demonstration next year. By the end of next year, our privately funded development program will have been ongoing for over seven years with expenditures of over $25 million. The duration and expenditure level attest to AEP's and its partners' dedication and belief in this technology. The next step, however, will cost $110 million and is beyond our capability, given the current regulatory and financial environment

It is our hope that forums such as this can consolidate funding support and be instrumental in developing mechanisms for funding technology such as PFBC. Thank you, Senator.

[The prepared statement of Dr. Markowsky follows:]

AMERICAN ELECTRIC POWER'S PRESSURIZED FLUIDIZED BED COMBUSTION DEVELOPMENT PROGRAM

By

James J. Markowsky Ph. D.
Manager, Analytical And R&D Section
American Electric Power Service Corporation

August 9, 1983

The object of my presentation today is to outline American Electric Power's Pressurized Fluidized Bed Combustion (PFBC) Development Program. This is a privately funded development program and is being carried out in conjunction with STAL-LAVAL Turbin AB, a subsidiary of the Swedish Manufacturer, ASEA; and Deutsche Babcock, a diversified West German Company.

The PFBC process is a relatively new technology, which AEP considers to be the most economic and environmentally attractive method for future generation of electric power with high sulfur coal.

Before I proceed with outlining AEP's PFBC development program, I first want to briefly describe the combustion process within a fluidized bed and distinguish between atmospheric fluidized bed combustion (AFBC) and pressurized fluidized bed combustion.

In fluidized bed combustion (FBC), the sulfur in the coal is removed during the combustion process. Crushed coal and a sulfur sorbent (dolomite or limestone) are continuously injected into a vessel, where the coal is burned at a relatively low temperature while in contact with the sulfur sorbent. Air is fed in from the bottom of the bed giving rise to turbulent coal and sorbent particle motion, which resembles a boiling-fluid like appearance.

FBC can take place either at atmospheric pressure (AFBC) or at elevated pressure (PFBC) (see Figure 1). In AFBC, the steam generated from in-bed boiler tubes is used to drive a conventional steam turbine. Combustion gases from the bed are cooled by water tubes above the bed.

In PFBC, the fluidized bed merges a gas turbine with a steam turbine in a combined cycle arrangement as shown in Figure 2.

The gas turbine portion of the cycle is driven by combustion gases from the fluidized bed, which have been cleaned by a series of cyclone dust separators. The gas turbine, in turn, drives both an air compressor, which provides combustion air to the fluidized bed; and a generator, which produces electric power.

Gases exhausting from the gas turbine still have considerable energy, which is used to preheat feedwater for the steam turbine cycle. This preheated feedwater is then sent to tubes within the fluidized bed, where conversion to steam takes place. The steam is used to drive a steam-turbine generator, producing additional electric power. The combined cycle nature of PFBC results in more efficient generation of electric power from high sulfur coal.

The ultimate goal of the AEP development program is the commercialization of the cycle shown in Figure 3. This commercial cycle would incorporate a supercritical, single reheat steam cycle coupled to a gas turbine cycle. A commercial plant comprising of one unit will have a gross electrical output of 665 MW.

Each gas turbine produces 75 MW for a total of 150 MW of gas turbine power. The balance (515 MW) is produced by one steam turbine. The net efficiency is 40%.

Next, I will address the advantages of PFBC for electric power generation. The next two figures (4 and 5) indicate the environmental and economic advantages, respectively, of using PFBC over conventional pulverized coal-fired power plants with wet limestone flue gas desulfurization (FGD). The advantages, which are summarized in Figure 6, are:

1) Over 90% SO_2 capture with high sulfur coal,
2) Modular plant design, which allows smaller plant sizes with minimal impact due to diseconomies of scale,
3) One third less NO_x emission,
4) Fuel flexibility,
5) One fifth less waste product, which is also a dry waste product,
6) Approximately 14% higher electrical generating efficiency, and
7) Approximately 10% lower capital cost.

These potential advantages are the driving forces behind AEP's development program, which I will now outline.

In December 1976, AEP, along with STAL-LAVAL, embarked on the first phase of the privately funded program, which was a six month feasibility study (Figure 7). The objective of the study was to assess the technical and economic merits of PFBC. This was performed by developing a conceptual design of a 170 MW demonstration plant to be located at AEP's Tidd facility in Brilliant, Ohio. The results of the study were encouraging, and it was decided to continue the program.

The next three phases of our program entailed both pilot plant test work and engineering and design of the proposed 170 MW demonstration plant.

At the conclusion of these phases, over two thousand hours of testing was completed using Ohio high sulfur coal and dolomite. All of the testing was performed at the British Coal Utilization Research Laboratory at Leatherhead, England.

The test programs and design efforts were successful in substantiating the merits of PFBC technology, and it was decided to construct an intermediate size facility prior to construction of a demonstration plant.

In 1980, however, it became clear that the new Administration was redirecting the Federal Government's role in energy development in that Federal funding would no longer be available for demonstration projects. This was a blow to our program as prior to this we had an ongoing dialogue with the U. S. Department of Energy (DOE) with respect to their cost-sharing in the construction of the demonstration plant. Up to this point, DOE had indirectly participated in our program by partially funding some of the pilot plant test work.

Although this was a disappointment, we decided to continue with our development program.

The next phase of the program was intended to perform the detailed design of the 170 MW demonstration plant. In addition to the design effort, a 15 MW (thermal) Component Test Facility (CTF) was constructed in Malmo, Sweden to be operated on high sulfur coal. The purpose of this facility was to verify, at a reasonable cost, the operation and reliability of an integrated PFBC system. An artist's rendering of the CTF is shown in Figure 8. We have shipped 2800 tons of Ohio and Indiana high sulfur coal along with 1400 tons of Ohio and Indiana dolomite to this facility.

The preoperational testing, and the test program currently planned will entail 2000 hours of operation at this facility. To date, over 500 hours of operation has been accomplished.

Through 1982, 23.3 million dollars has been spent in support of this program. AEP's portion has been 3.2 million dollars, our European partner's portion has been 16.7 million dollars, U. S. DOE's portion has been 2.6 million dollars, and the remaining $800,000 from other interested parties.

Due to anticipated funding difficulties, we are currently modifying the design of the demonstration plant to reduce its size from 170 MW to 64 MW. The cycle arrangement of the 64 MW Tidd Demonstration Plant is shown in Figure 9. An existing steam turbine at Tidd would operate at approximately half power with an output of 49.7 MW while the STAL-LAVAL GT 35 gas turbine output will be 14.2 MW. It is currently anticipated that the 64 MW demonstration plant will cost approximately 110 million dollars. Although the 110 million dollar demonstration plant cost is lower than the original 170 MW demonstration plant, availability of funding support clouds AEP's ability to demonstrate this highly attractive technology.

Figure 10 presents a schedule for the 64 MW demonstration plant based upon only technical constraints.

The current phase of the development program entails both the operation of the CTF and completion of the preliminary design of the 64 MW demonstration plant by the end of 1984. Assuming the result from both efforts are positive and funding is available, construction could commence in 1986 with operation in 1988. If this schedule can be met, the first commercial size PFBC facility could be operating by the mid-1990's.

It is apparent that the commercialization process is both long and costly, thereby, beyond the financial means of private industry and especially a regulated electric utility.

However, AEP and its partners are continuing to develop PFBC and will be in a position to assess the technological readiness for demonstration next year. By the end of next year, our privately funded development program will have been ongoing for over seven years with expenditures of over $25 million. The duration and expenditure level attest to AEP's and its Partners' dedication and belief in this technology. The next step, however, will cost $110 million and is beyond our capability, given the current regulatory and financial environment.

It is our hope that forums such as this one can consolidate support for technologies such as PFBC and be instrumental in formulating funding mechanisms, which would provide funding of demonstration programs such as PFBC.

FIGURE 1

THE FLUIDIZED BED CONCEPT

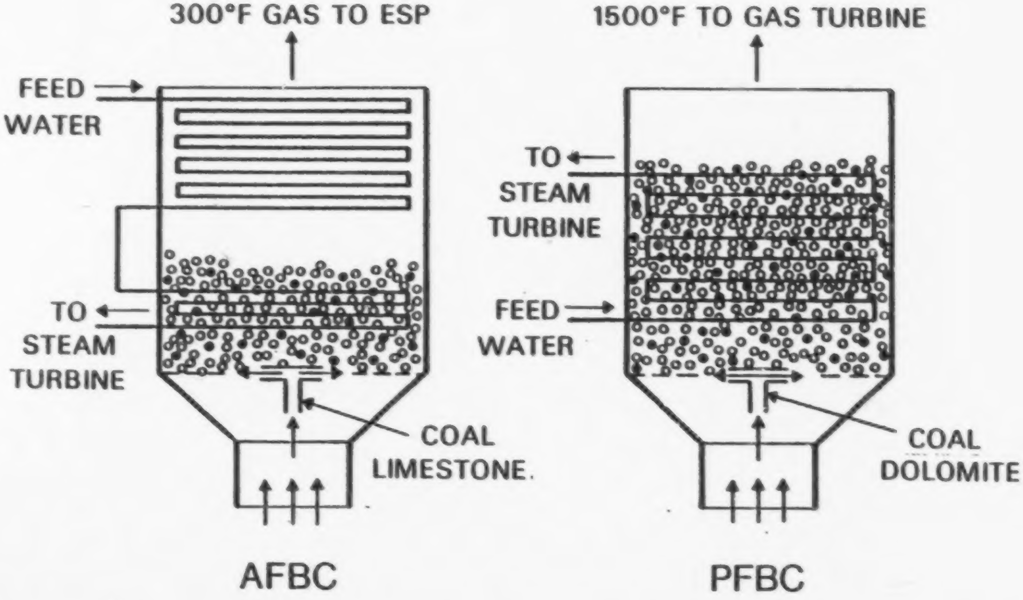


FIGURE 2

PFBC PLANT

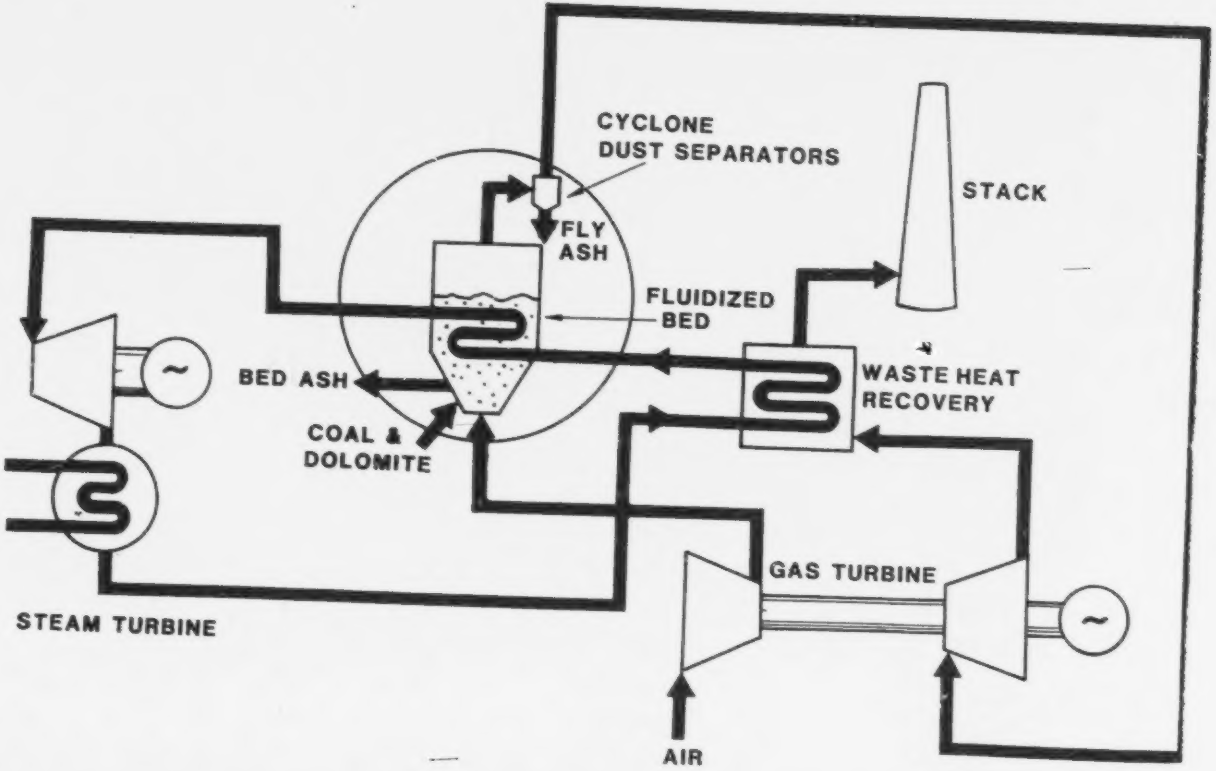
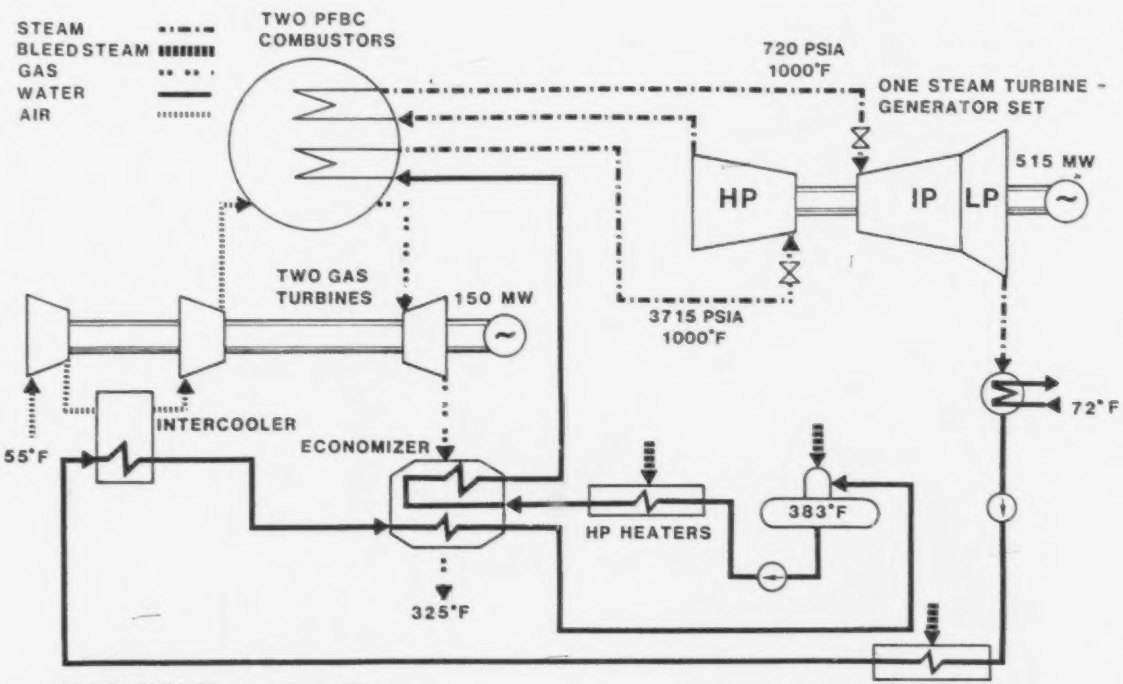


FIGURE 3



GROSS OUTPUT	665 MW
AUX. POWER	25 MW
NET OUTPUT	640 MW
THERMAL EFF NET	40% (HHV)

COMMERCIAL PFBC PLANT (TWO MODULE)

FIGURE 4

ENVIRONMENTAL COMPARISON
CONVENTIONAL PLANT with FGD SYSTEM vs. PFBC PLANT

TECHNOLOGY	SO_2 REMOVAL PERCENT	NO_x lb/10^6 BTU	SLUDGE-ASH TONS/MWH
WET LIMESTONE FGD SCRUBBERS	90	0.5-0.6	0.23[1]
PFBC	90-95	0.2-0.4	0.18[2]

NOTE: BASED ON 4 PERCENT SULFUR COAL WITH HEATING VALUE OF 11,500 BTU/LB.

[1] BASED ON OXIDIZING THE SLUDGE TO CONVERT MAINLY TO SULFATES AND REMOVING WATER SUCH THAT RESULTING SLUDGE WILL HAVE 65 PERCENT SOLID BY WEIGHT.

[2] DRY SOLIDS AND 90 PERCENT SULFUR REMOVAL.

FIGURE 5

COST COMPARISON
CONVENTIONAL PLANT with FGD SYSTEM vs. PFBC PLANT

DESIGN CONDITIONS	CONVENTIONAL PLANT with FGD SYSTEM	COMMERCIAL-PFBC PLANT
Net Capacity (MW_e)	600	640
Net Heat Rate (BTU/kw-hr)	9,770	8,530
COST SUMMARY (1983 DOLLARS)		
Total Capital Requirements (10^6 \$)	765	730
Capital Cost, \$/ kw	1275	1140
Cost of Electricity, Mills/kw-hr	75.3	69.0
Fixed Charge, Mills/kw-hr	48.2	43.2
O&M Cost, Mills/kw-hr	9.0	10.0
Fuel Costs, Mills/kw-hr	18.1	15.8

FIGURE 6

SUMMARY

ADVANTAGES OF PFBC PLANT vs. CONVENTIONAL PLANT with FGD SYSTEM

GREATER ECONOMY, EFFICIENCY AND ENVIRONMENTAL COMPATIBILITY SUCH AS:

1. Over 90% SO_2 Capture With High Sulfur Coal.
2. Modular Plant Design Which Allows Smaller Plant Sizes With Minimal Impact Due to Diseconomies of Scale.
3. Lower NO_x Emissions.
4. Fuel Flexibility.
5. Dry Waste Products.
6. Higher Electric Generation Efficiency.
7. Lower Capital Cost.

FIGURE 7

PFBC DEVELOPMENT PROGRAM THROUGH 1982

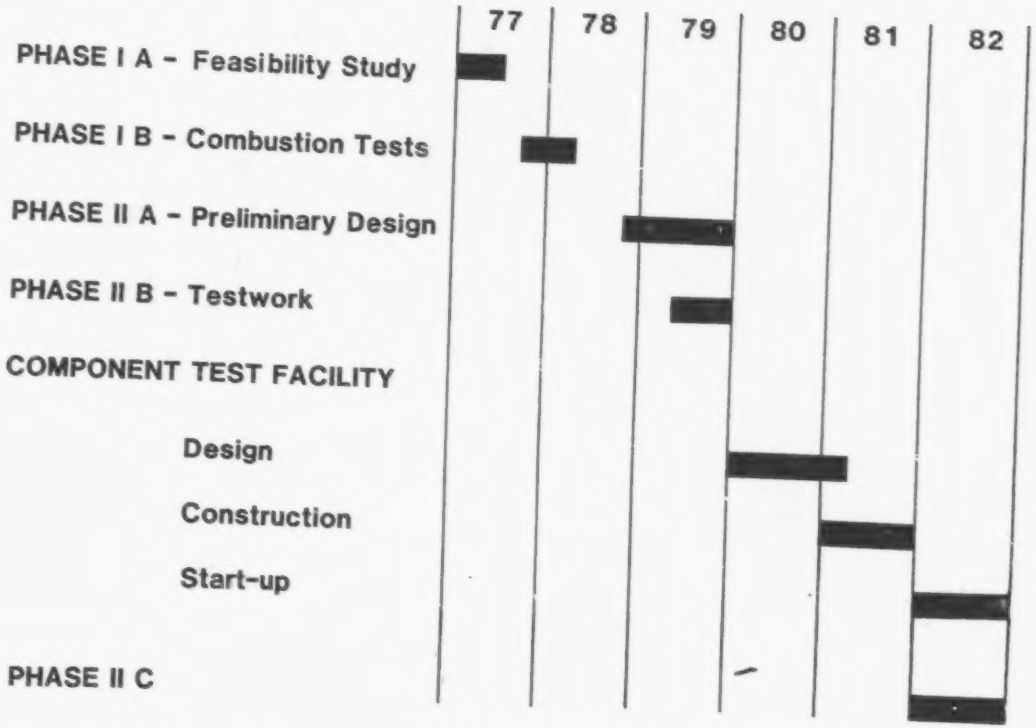
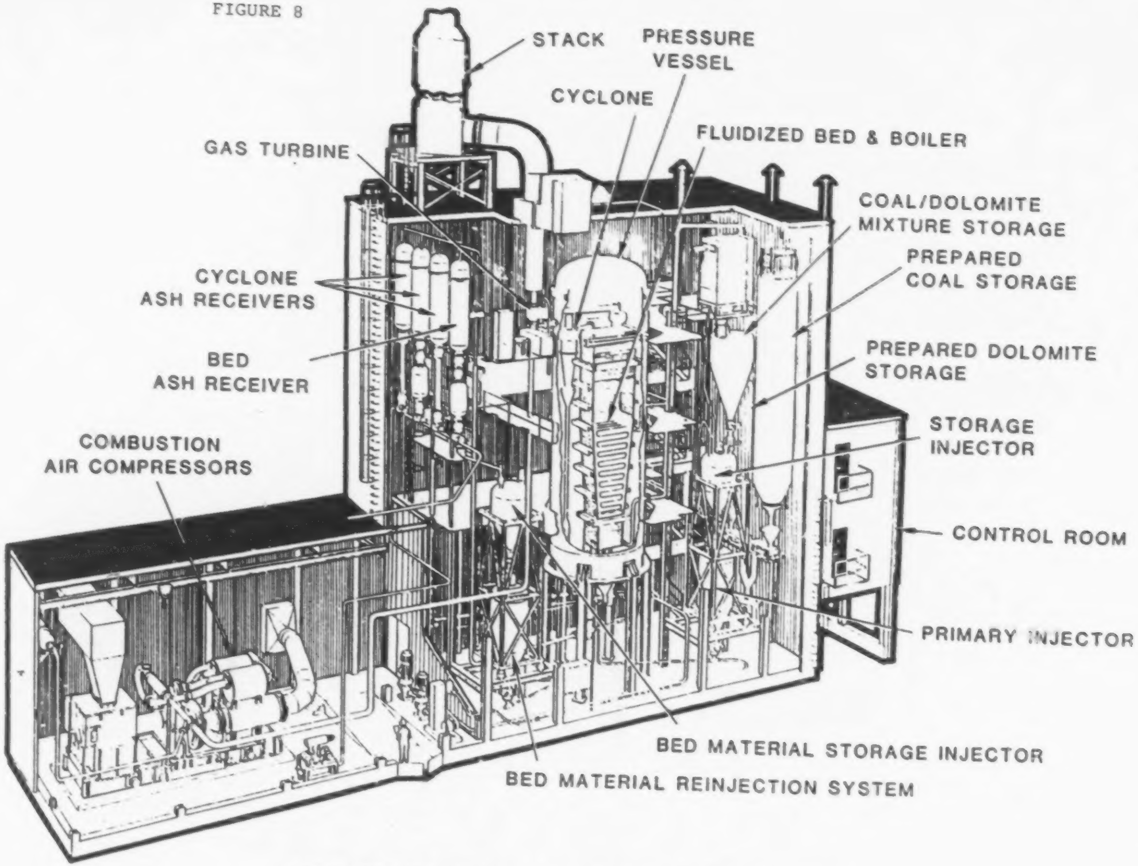
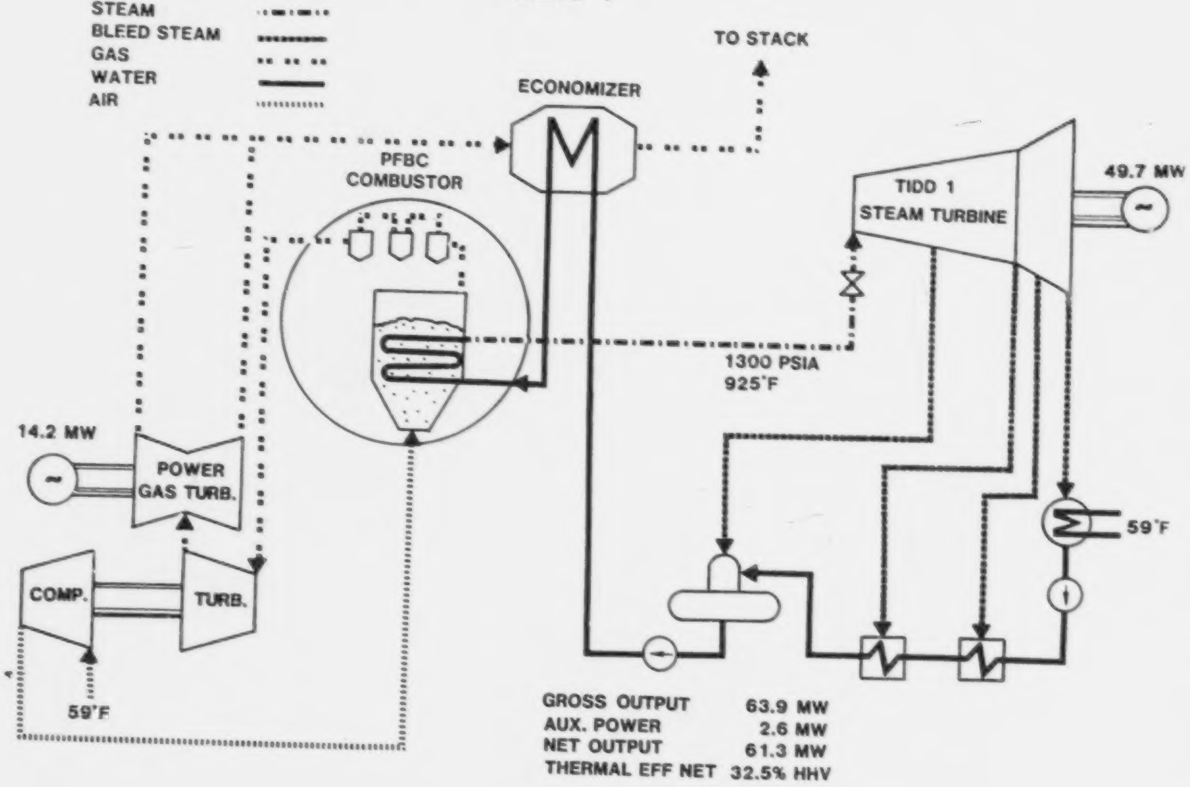


FIGURE 8



COMPONENT TEST FACILITY

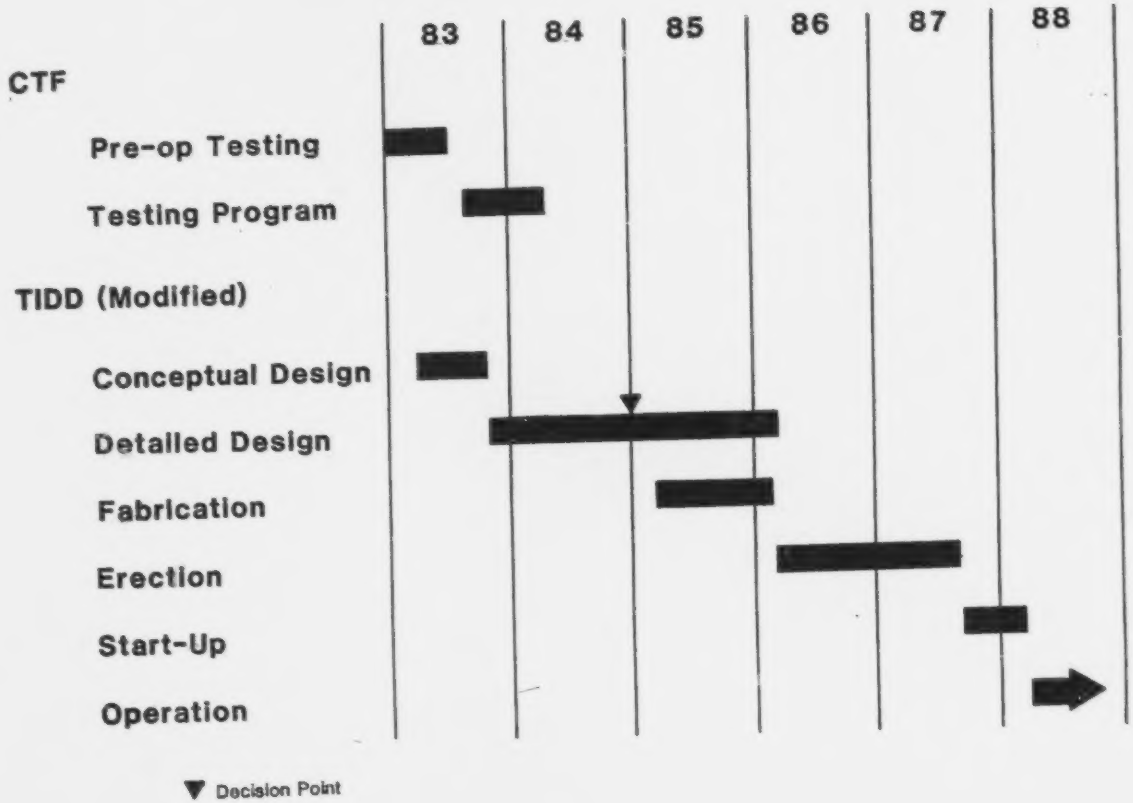
FIGURE 9



TIDD PFBC DEMONSTRATION PLANT CYCLE

FIGURE 10

CURRENT PFBC PROGRAM SCHEDULE



Senator **Warner**. Thank you. A very helpful and inspiring message. Pretty expensive.

Dr. **Markowsky**. As all demonstrations are, sir.

Senator **Warner**. Now Dr. High, Tennessee Valley Authority.

STATEMENT OF DR. MICHAEL D. HIGH, DIRECTOR, DIVISION OF ENERGY DEMONSTRATIONS AND TECHNOLOGY, TENNESSEE VALLEY AUTHORITY

Dr. **High**. Thank you, Mr. Chairman. I found that I can reduce my talk by a factor of two since Jim has already presented what fluidized combustion is all about. I am Michael D. High, Director of the Division of Energy Demonstrations and Technology of the Tennessee Valley Authority, which is a fancy way of saying that I direct the research and development for that organization, the utility end of it.

I appreciate this opportunity this afternoon to address this subcommittee and TVA applauds the initiative you have taken to explore the opportunities to accelerate the development of enhanced coal technologies for increased utilization of domestic fuel resources.

In 1982, TVA burned 27.5 million tons of coal in its 12 central steam plants. TVA uses a combination that I'm sure you are aware of hydroelectric, nuclear, coal-fired, pumped storage, and combustion turbines in our generation. But we attributed last year about 58 percent of our generation to coal. From these figures its easy to understand why our concern and interest is coal and will be in the future.

On a broad scale, TVA investigates and monitors a number of emerging coal-related technologies for future use. For example, we are presently pursuing an interest in demonstration of the dry scrubber technology for a large scale utility boiler. But our major emphasis in the last few years has been on the development of the atmospheric fluidized bed combustion. And my statement today will dwell on the development of this technology.

We've looked at the AFBC technology now since about 1977. We became earnestly involved in it in about 1980 when our board of directors authorized the construction of a 20 MW pilot plant. The numbers that we have looked at in the EPRI assessment guides project the AFBC price to be 10 to 15 percent less costly than a conventional coal fired unit with scrubbers. This is for eastern high-sulfur coal. In the West it turns out the capital advantages project to be somewhat greater than that because of the coal characteristics in that region of the country. We conservatively estimate that the successful AFBC development could result in a saving to the Nation's electric consumers of $10 billion over the next 10 years.

To achieve rapid commercial acceptance for this, we believe as do most other people in the utility industry, that a utility-scale demonstration to verify reliability, performance and costs is needed. TVA, with significant support from Congress, took the first step leading to such a demonstration by constructing a $68 million 20 MW AFBC pilot plant located at Paducah, KY. On that facility, we split the funding 50-50; $39 million of that was provided by the

Federal Congress and $39 million is TVA private funds. In addition, we have invested some $10 million in this technology of R&D support. Construction on this activity was completed in May 1982 and a major test program, currently underway, is being jointly funded by ourselves and the Electric Power Research Institute, to develop the technical and environmental performance data to be used in the design and construction of a demonstration plant. The pilot plant has operated approximately 2,400 hours in the past year and consumed about 12,000 tons of coal and 6,000 tons of limestone. I hesitate to say that this was 12,000 tons of western Kentucky coal, but that's what we burned. To date, the plant has exceeded our expectations during the start up and the initial testing. Although not optimal, the plant is consistently operated with industrial efficiencies in the range of 96 to 98 percent. This compares favorably with the efficiency normally achieved with the pulverized-coal-fired boiler and from that standpoint indicates that the AFBC boiler should be able to compete with the traditional boilers.

The pilot plant has demonstrated that the process can meet new source performance standards for sulfur dioxide, oxides and nitrogen, in coal particulate emissions without flue gas desulfurization equipment. The new source performance standard for SO_2 coal-fired utility boiler require 90-percent removal and actually 1.2 pounds per million Btu. Depending on the amount of limestone we've fed to the combuster in the unit the pilot plant has achieved a range of sulfur removals from 85 to 98 percent. This is equivalent to 1.1 pounds and 0.15 pounds to million Btu, respectively. That coal burned in that plant, as I indicated, is a high sulfur bituminous coal with an average sulfur content of 4.2 percent contained in western Kentucky mines.

The inherent advantage that was alluded to in the AFBC process is the ability to burn coal with low NO_x emissions. The operating experienced today consistently produces NO_x emissions of 0.2 to 0.4 per million Btu as compared to new source performance standards for NO_x of 0.6. The pilot plant we have has installed a bag-house and our total particulate emissions consistently run at 0.01 to 0.02 pounds per million Btu. These bags also compare very favorably with the present standard of 0.03.

Also, we have not found any environmental unacceptable practices in disposing of that dry waste. Clearly, these initial results further justify our belief that the AFBC on recent studies in our success with the pilot plant we have concluded that the next major step is a demonstration. This demonstration will probably be an add on boiler using the current existing turbogenerator sets at the Paducah, KY facility. We think this would be the lowest cost approach to demonstrate the central elements of the AFBC technology. The design fuel for such a demonstration plant would be a high-sulfur Illinois basin coal, as typified by Kentucky No. 9. However, fuel flexibility will be considered with testing of alternate fuels. The preliminary process for the construction of such a facility is $200 million. We would anticipate beginning detailed design in 1984 with power on the grid sometime in the mid-1989, 1990 time period. This timetable, we believe, would provide the electric power industry with the option of selecting an AFBC coal-fired plant in the early 1990's to provide added or replacement power to the grid in the mid 1990's.

The TVA and the Duke Power Co. and the Commonwealth of Kentucky have jointly responded to a request made by the Electric Power Research Institute soliciting a host site for this demonstration plant. We have offered to host the demonstration, as we pareviously discussed, and will contribute financially to the design, construction and operation of such a plant. We will be pursuing commitments from other funding sources vigorously as well. In fact, the EPRI board directors are meeting today to vote on this proposal to host the AFBC demonstration project and the advisory structure at EPRI and their staff have recommended EPRI board approval of the project and a contribution by them of $75 million.

As you know, the Senate has also approved an amendment to a pending appropriations bill which would appropriate an additional $30 million for the project for fiscal years 1985 and 1986. These appropriations, if the bill is passed by the Senate and approved by the House, would make it easier to secure the remaining funds for the demonstration plant and reduce the risk of extending the schedule for this development. This relatively small federal investment made at a critical time in the development of the technology would significantly help influence obtaining substantial investment from private sources.

From TVA's standpoint, AFBC in an important and viable technology which can significantly benefit the Nation. The interest shown by this subcommittee in the development of enhanced coal technologies is of great benefit in pointing out the national significance of developing these technologies in a timely manner.

I appreciate the opportunity to present out views and program. I would be pleased to answer any questions this subcommittee has.

[The prepared statement of Dr. High follows:]

STATEMENT OF MICHAEL D. HIGH
DIRECTOR
DIVISION OF ENERGY DEMONSTRATIONS AND TECHNOLOGY
TENNESSEE VALLEY AUTHORITY
BEFORE THE
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
AUGUST 9, 1983

Mr. Chairman, I am Michael D. High, Director of the Division of Energy Demonstrations and Technology of the Tennessee Valley Authority (TVA).

I appreciate this opportunity to address this subcommittee, and we applaud the initiative you have taken to explore the opportunities to accelerate the development of enhanced coal technologies for increased utilization of domestic fuel resources.

In 1982, TVA burned 27.5 million tons of coal in 12 central station steam plants. TVA, which uses a combination of hydroeletric, nuclear, coal-fired, pumped storage, and combustion turbine generating plants, attributed 58 percent of the total generation in 1982 to coal. From these figures it is easy to understand TVA's strong interest in coal now and in the future.

TVA expects to continue to burn large quantities of coal for many years to come. Even with a number of nuclear units coming online, coal will continue to provide almost half of our generation. Therefore, TVA is heavily committed to developing new coal technologies to enable us to augment or replace existing coal-fired steam plants.

On a broad scale, TVA is investigating and monitoring a number of emerging coal-related technologies for future use by the electric power industry. We are presently considering demonstrating a dry scrubber for the use of high-sulfur coal in an environmentally acceptable manner. The major emphasis at TVA in this area, however, is the development of atmospheric fluidized bed combustion (AFBC). My statement today will outline the development of this technology, and in particular, our AFBC activities.

AFBC technology offers the electric power industry an opportunity to utilize the abundant and less costly coals which are not now being used in conventional power plants due to environmental standards. During the AFBC combustion process, limestone is added with the coal. The limestone reacts with the sulfur dioxide released from the burning coal and prevents the sulfur dioxide from escaping into the atmosphere. Because the capture of sulfur is inherent during the AFBC combustion process, the opportunity exists to use these coals fully while achieving superior environmental performance. Due to low combustion temperatures, another benefit is a significant reduction in the production and release of nitrogen oxides from those of a conventional coal-fired plant. In addition, comprehensive Department of Energy studies indicate that the dry solid by-product from this process (calcium sulfate) may have useful applications or, at the least, provide a material which can be conveniently disposed of in an environmentally acceptable manner. Based on studies and forecasts by the Electric Power Research Institute (EPRI) and Ebasco Services, AFBC generating capacity could reach 25 to 50 GW by the year 2000, which would be 3 to 6.5 percent of the total U.S. electric generation. Approximately 50-100 million tons per year of coal would be used in these plants.

In the East, the capital costs of an AFBC plant are projected to be 10-15 percent less (in dollars per kW of capacity) than a conventional coal-fired unit with scrubbers. In the West, the capital advantage is projected to be 15-20 percent. The operating costs of an eastern AFBC plant are projected to be 5-10 percent less (in mills per kWh generated), while in the West, operating costs are projected to be 7-12 percent less. Plants burning western coal will need only small amounts of limestone, if any at all, to meet environmental standards. TVA, Duke Power Company, and the Commonwealth of Kentucky (the Principals) conservatively estimate that successful AFBC development could result in a saving to the Nation's electric consumers of ten billion dollars over the next 20 or 30 years.

To achieve rapid commercial acceptance by the electric power industry, this technology needs a utility-scale demonstration to verify reliability, performance, and costs. TVA, with significant support from Congress, has taken the first major step leading to a utility-scale demonstration by constructing a $68 million 20-MW AFBC pilot plant in Paducah, Kentucky. Construction activities on this facility are complete, and the unit began shakedown operations in May 1982. A major test program, funded jointly by EPRI and TVA, is underway to develop the technical and environmental performance data to be used in the design and construction of a demonstration plant. The pilot plant has operated approximately 2,360 hours and consumed approximately 11,950 tons of coal and 5,700 tons of limestone.

Based on recent studies, TVA has concluded that the next major step, a utility-scale demonstration facility, can be accomplished by replacing an existing pulverized-coal-fired boiler with an AFBC boiler. This approach will accomplish the goals of demonstrating the essential elements of the technology at a significantly lower cost than a new stand-alone facility.

The AFBC demonstration facility would be located at TVA's coal-fired Shawnee Steam Plant in Paducah, Kentucky. To demonstrate the technology, an AFBC boiler would be constructed beside an existing unit at the plant as a replacement for the existing boiler. The AFBC boiler would be capable of generating approximately 160 MW of electric power and would make maximum use of the existing turbogenerator set and other associated equipment. The design fuel for the demonstration would be high-sulfur Illinois basin coal, as typified by Kentucky number 9. However, fuel flexibility will be considered with testing of alternate fuels during the test program. The preliminary cost estimate for construction of the AFBC demonstration at Shawnee is $200 million. It is anticipated that a 3-year test and demonstration period will cost approximately $20 million.

The schedule as presently proposed, allows an adequate amount of time to evaluate the pilot plant test results prior to freezing boiler designs. On this schedule, detailed design and erection of the facility will begin in 1984 and will be completed by mid-1989. Operational testing, producing power for TVA's grid, would begin in 1989. This timetable provides the electric power industry with the option of selecting an AFBC coal-fired plant in the early 1990s to provide added or replacement power to their grid in their mid-to-late-1990s.

The Principals have jointly responded to a request by EPRI soliciting a host site for a demonstration of an AFBC steam generator in the range of 100 to 200 MW and have offered to host the demonstration previously discussed and contribute financially to its design, construction, and operation. The Principals will be pursuing commitments for funds and/or inkind services from EPRI, other power systems, foreign countries, coal companies, equipment vendors, and others in order to secure the resources necessary to build the demonstration facility. In fact, the EPRI board is meeting today to vote on the TVA/Duke/Kentucky proposal to host the AFBC demonstration project. The EPRI advisory structure and staff have recommended to the EPRI board that they approve the project and contribute $75 million. The Senate has also approved an amendment to a pending appropriations bill which would appropriate a total of $30 million for the project for fiscal years 1985 and 1986. These appropriations, if the bill is passed by the Senate and approved by the House, would make it easier to secure the remaining funds required for the demonstration plant and reduce the risk of extending the schedule due to insufficient funds. This relatively small Federal investment made at a critical time would significantly help influence a substantial investment from private sources. The investment will be of benefit to the entire Nation and ensure the continued use by the electric power industry of domestic coal resources in a sound environmental and economic manner.

From TVA's viewpoint, AFBC is an important and viable technology which can significantly benefit the Nation. The interest shown by this subcommittee in the development of enhanced coal technologies is of great benefit in pointing out the national significance of developing these technologies in a timely manner.

I appreciate the opportunity to present our program and views. I would be pleased to answer any questions this subcommittee has.

Senator WARNER. That's fine. That's very good news. I guess you want me to vote for that $30 million?

Dr. HIGH. Yes, that would be very nice.

Senator WARNER. Senator Huddleston had a little hand in that?

Dr. HIGH. Yes sir, Senator Huddleston has a hand in that.

Senator WARNER. He's a fine man. Now, we'll hear from Mr. Davis.

STATEMENT OF JAMES M. DAVIS, JR., SENIOR VICE PRESIDENT, FUEL AND MATERIALS MANAGEMENT, CAROLINA POWER & LIGHT CO.

Mr. DAVIS. Thank you, Senator Warner. Carolina Power & Light Co. is pleased to have this opportunity to share its views on the desirability and potential for the increased use of coal in electric generation. I have filed a written statement, Senator, and in the interest of time I will simply summarize the content.

Senator WARNER. Your statement will be put in in its entirety.

Mr. DAVIS. Thank you. Just by way of introduction, Carolina Power & Light Co. provides electric service to a population of approximately 3 million in an area of 30,000 square miles. This area covers almost one-half of the State of North Carolina and about one-fourth of the State of South Carolina.

Our company is predominantly a coal and nuclear based operating utility with 8 coal-fired plants, including 19 units, and 2 nuclear plants with three operating units. In 1982, coal from the central Appalachian region provided about 75 percent of our electric generation and nuclear power contributed about 22 percent and the balance was made up of 2-percent hydropower and less than 1-percent oil and natural gas.

During 1982, we burned approximately 9.6 million tons of coal which is the largest burn of record on our system. This year we expect to burn about 10 million tons and even more next year. Last year of the 9.6 million tons, approximately 830,000 tons originated in mines of our host today, the Commonwealth of Virginia. CP&L expects to purchase about 900,000 tons of coal from Virginia in 1983 and perhaps over 1 million tons in 1984.

Our commitment to the utilization and expansion of the use of central Appalachian coal is evidenced by the strong presence of coal units in our present base load capacity and our plans for the future. In 1980 we brought a 270 MW Roxboro Unit 4 into commercial operation and in March of this year we brought our new 720 MW Mayo Unit 1 online. A further Mayo Unit, Unit No. 2, is currently planned to begin commercial operation in 1992. So we are very heavily committed to the use of coal both at present and in the future. We have that commitment and have used coal historically because we believe that coal provides an economical and reliable fuel, which has enabled us to meet two of our more important objectives. One is to provide reliable electric service to our customers at minimum cost compatible with the environment. And secondly, to maintain adequate generating reserves necessary to support the economic development of our area. CP&L's commitment to coal in the future is based on the expectation that coal usage will continue to enable us to meet these objectives. This expectation can only be fulfilled, however, so long as Congress maintains a rational, equitable, and flexible regulatory framework to govenr the usage of coal in the generation of electricity in this country.

The United States needs a healthy utility industry to assure the existence of an adequate supply of electric service to support economic development. I certainly share the views expressed this morning that our base of coal will depend on the health of the economy and economic recovery. Certainly a part of that is a healthy utility industry so that we can provide the electric supply to support the economic recovery and development. Its actually essential to the overall development of our economy and the ability of our utilities to make investments necessary to assure this supply will actually support the industrial revitalization to provide supply in the future. Even with the conservation that we've been able to accomplish with economic recovery, there could easily be a requirement for 300,000 to 400,000 megawatts of additional capacity by the year 2000.

Large capital invetments will certainly be necessary to support that development as we go forward. And a part of that will be environmental expenditures. We have already invested large capital requirements in our existing plant. We need to take maximum advantage of that invested capital. Large capital investments are required for coal-fired plants to meet environmental standards as other environmental expenditures. Since 1968, we have invested approximately $400 million in facilities to protect the environment and additional expenditures are required each year. Moreover, as we have discussed today, several legislative proposals currently before Congress could severely limit coal as an option for existing plants, as well as new capacity.

It is essential to have reasonable environmental regulations which provide utilities with flexibility in attaining applicable standards. In developing these standards, we must very carefully study the cost/benefits to make sure that the impact of these regulations will, in fact, produce a benefit to the customers and the overall company. Now more than ever, when the economy is struggling to recover and millions of people remain unemployed, the case must be made for reasonable environmental regulation. We must avoid large capital expenditures unless significant benefits are likely to result.

Now looking at the question of technology as it applies to environmental standards and control, we certainly support the development of new technologies including those related to the increased use of coal. We have in our company a research budget and we also support industry efforts through contributions to the Electric Power Research Institute and the Edison Electric Institute. We are following closely the developments related to technologies, specifically those that have been discussed today, fluidized bed combustion and coal gasification. Its our view and belief that these technologies will develop to the point where they are practical and of commercial use to electric utilities. That is some time in the future and we expect those technologies will be a factor in the long-term energy supply.

We wish to point out, however, and the thrust of my remarks is that we presently have conventional technologies for the use of coal which have been developed to a very high degree. It would be a mistake to rely completely on new technologies and not obtain the maximum benefits from our present technology. For example, rather than imposing the use of new technologies as mean for achieving emission standards, we should allow the use of existing technologies to also achieve our goals. CP&L, for example, has chosen what I would call conventional coal utilization technologies. These include the use of low-sulfur coal as a means of meeting emissions limitations. Sophisticated coal procurement and load dispatch programs have allowed us to develop and select coal sources and to blend those coal sources and supplies to obtain maximum boiler performance and reduced environmental impact. We have been able to reduce our emissions each year since 1980. Congress should take whatever action is required to assure that this option for meeting emission limitations is available for new plants as well as existing plants. CP&L also uses the beneficiation, or coal washing, on virtually all of our coal. Over 95 percent of our present coal is subjected, to some extent, to washing at the present time. This process is used for ash reduction and has the effect of increasing the energy content of the coal. In addition, the sulfur content in some coals is reduced in the beneficiation process.

In this connection, we suggest that Congress consider the concept of granting utilities credits or benefits to utilities which have historically maintained and reduced their emissions at low levels. For example, our average SO_2 emissions from all of our coal-fired generating plants has been consistently well below allowable limits. Our emmissions on a system average, at this time, are below 1.5 pounds per million Btu.

CP&L is committed to the expanded use of coal as a primary source of fuel for our electric generation which is vitually needed to sustain economic development. With prudent regulations, we believe we can pursue through existing plans to use conventional low-sulfur coal technology and provide electricity with minimum impact upon the environment and maximum economic benefit to our customers and the area we serve. Optimum use of conventional technologies will also compliment the development of the new technologies. To this end we support environmental regulations which are cost effective and technologically sound.

And I appreciate the opportunity to participate in this hearing.

[The prepared statement of Mr. Davis follows:]

HEARING ON

ADVANCED COAL TECHNOLOGY: COAL'S MARKET FOR THE 80'S

AUGUST 9, 1983

STATEMENT BY JAMES M. DAVIS, JR.

CAROLINA POWER & LIGHT COMPANY

Senator Warner, fellow speakers, industry representatives, and other guests, Carolina Power & Light Company is pleased to have this opportunity to discuss its views regarding the desirability of increased usage of coal in the generation of electricity. I am James M. Davis, Jr., Senior Vice President for Fuel and Materials Management for Carolina Power & Light Company.

CP&L provides electric service to a population of approximately 3 million in an area of 30,000 square miles. This area covers almost one-half of North Carolina and about one-fourth of South Carolina.

CP&L is predominantly a coal and nuclear generating utility with eight coal-fired plants (19 units) and two nuclear plants (three units). In 1982, coal from the Central Appalachian region provided about 75 percent of CP&L's electric generation, and nuclear contributed about 22 percent; the balance was made up of two percent hydropower and 1 percent oil and natural gas.

In 1982, CP&L burned approximately 9.6 million tons of coal on its system, a record high. This year we expect to burn about 10 million tons and even more next year. Of the 9.6 million tons burned in 1982, approximately 830,000 tons originated at mines located in Virginia. CP&L expects to purchase approximately 900,000 tons of Virginia coal in 1983 and perhaps over a million tons in 1984.

CP&L's commitment to the utilization and expansion of the use of Central Appalachian coal is evidenced by the strong presence of coal generation in the Company's recent additions to base load capacity and our plans for the future. In 1980 we brought our 720 Mw Roxboro Unit 4 into commercial operation; and in March of this year, we brought our 720 Mw Mayo Unit 1 on-line. The second Mayo unit, a duplicate of the first, is currently planned to begin commercial operation in 1992.

CP&L's usage of coal, historically, has resulted to a large extent from the fact that it has been an economical and reliable fuel, which has enabled us to meet two of our most important objectives: (1) to provide reliable electric service to our customers at the minimum cost compatible with protection of the environment; and (2) to maintain adequate generating reserves necessary to support the economic development of our service area. CP&L's commitment to coal generation for the future is based upon the expectation that coal usage will continue to enable us to meet those objectives. This expectation can only be fulfilled, however, so long as Congress maintains a rational, equitable, and flexible regulatory framework to govern the usage of coal in the generation of electricity in this country.

The United States needs a healthy utility industry to assure the existence of an adequate supply of electric power to support economic development. Today, unfortunately, the outlook for new base-load generation of any kind remains highly uncertain. This situation is attributable in part to the increasingly unwieldy and unnecessarily inflexible body of regulations governing many aspects of the electric industry's activities.

No one can know precisely what electricity demand will be in the future, but it is clear that it will be closely related to the growth in the national economy. The relationship between use of electricity and economic development has held remarkably stable and consistent since World War II even while total energy use relative to GNP has declined in recent years. The stage is set for even greater reliance on electric energy in our changing economy. Projections are that electricity's share of the total national energy picture will increase from about one-third now to as much as one-half by the end of the century.

Electricity will be both a result of and a catalyst for economic development. Whether America modernizes and retools its traditional heavy industries like steel and autos or focuses on development of the so-called "Sun-Rise Industries" such as electronics and information-oriented enterprises, we will need steadily larger amounts of electric power.

A healthy electric utility industry is essential to an overall economic environment within which growth companies flourish. The ability of America's electric utilities to make the investments necessary today to assure adequate supplies tomorrow is critical to the industrial revitalization of the country. No industry or enterprise will risk siting a plant where power supplies are at all questionable. Adequate supplies must also be assured well into the future.

Even with a strong conservation ethic, there could easily be a need for 300,000 to 400,000 megawatts of additional new capacity by the year 2000 to support economic growth and replace older units. This would require over 400 new 700-MW units. The logical fuels for this new base-load generation are coal and uranium--abundant domestic energy resources which can be efficiently utilized by proven technologies. An electric energy mix based on coal and nuclear power was endorsed by the comprehensive study completed by the National Academy of Sciences in 1980. But utility financial constraints, numerous regulatory requirements, and political uncertainties complicate the future of both of these two means of power generation.

Large capital investments are required for coal-fired power plants to meet environmental standards. Since 1968, CP&L has invested approximately $400 million in facilities to protect the environment; and additional expenditures are required each year. Moreover, several legislative proposals currently before Congress could severely limit coal as an option for existing plants, as well as new plant capacity.

It is imperative that we have in this country reasonable environmental regulations which provide utilities with flexibility in attaining applicable standards. In developing standards, cost/benefit studies must be made to determine the impact such regulations will have on the utilities, their customers, and the overall economy. Now more than ever, when the economy is struggling to recover and millions of people remain unemployed, the case must be made for reasonable environmental regulation. We must avoid large capital expenditures unless significant benefits are likely to result. If, for example, costly flue gas desulfurization equipment (scrubbers) is mandated for all utilities, it will not be cost effective to install scrubbers on all existing units because of physical or economic constraints. Thus, coal plants now generating electric power which are not capable of being modified would have to be retired, further limiting the availability of electric power to serve economic development. Obviously, this is not in the best interest of a healthy United States economy. Any environmental stragety must allow, and encourage, the use of low-sulfur coal wherever and to the fullest extent it is available to reduce unnecessary capital expenditures and the unnecessary creation of scrubber waste.

CP&L supports the development of new technologies including those related to increased use of coal. We have a research budget within our Company and also support industry efforts through contributions to the Electric Power Research Institute and the Edison Electric Institute. We are following closely the developments related to coal technologies; specifically, fluidized bed combustion and coal gasification. We believe that these technologies will develop to the point where they are practical and of use to electric utilities. We expect that these new technologies will be a factor in the long-term energy supply.

We wish to point out, however, that we have conventional technologies for the use of coal which have been developed to a high degree. It would be a mistake to rely on new technologies and not obtain the maximum benefits from our present technology. For example, rather than imposing the use of new technologies as means for achieving emission standards, we should allow the use of existing technologies to achieve our goals. CP&L, for example, has chosen what I would call conventional coal utilization technologies. These include the use of low-sulfur coal as a means of meeting emissions limitations. Sophisticated coal procurement and load dispatch programs have been developed to select and blend coal supplies to obtain optimum boiler performance and reduced environmental impact. Congress should take whatever action is required to assure that this option for meeting emission limitations is available for new plants as well as existing plants. CP&L also uses the process of benefication, or coal washing, on virtually all of its coal. This process is used for ash reduction and has the effect of increasing the energy content of the coals. In addition, the sulfur content in some coals is reduced in the benefication process.

In this connection, we suggest that Congress consider the concept of granting utilities credits or benefits to utilities which have historically maintained emissions at low levels. For example, CP&L's average SO_2 emissions from its coal-fired generating plants have been consistently well below allowable limits.

CP&L is committed to the expanded use of coal as a primary source of fuel for the electric power generation which is vitally needed to sustain economic development in the United States. With prudent regulations, CP&L can pursue its existing plans to use conventional low-sulfur coal technology to provide electricity with minimum impact upon the environment and maximum economic benefit to its customers and the area it serves. To this end we support environmental regulation which is cost effective and technologically sound.

I appreciate the opportunity to participate in this hearing, and I would be pleased to answer any questions that you may have.

PERM21-F

Senator **Warner**. Have you run an analysis on the flue scrubbers and what it would cost you in capital investment likely to be passed on to your customers?

Mr. **Davis**. Yes, sir, Senator Warner. That is something we do on an ongoing basis. We do not have scrubbers at the present time because we've been able to reduce our emissons without them. But we are very conscious that we may be mandated to have them and we have looked carefully at the cost. You used an adjective earlier about extraordinary and I certainly think that fits the cost that we would look at on our system for a scrubber. I think it varies depending on the plant and the time at which you do it but I think the most direct comparison was looking at a conventional plant today, new coal-fired plants that may cost $800 per kilowatt, the scrubber would be expected to cost $200 per kilowatt.

Senator **Warner**. Of the eight or on top?

Mr. **Davis**. On top of that. An addition of about 25 percent. Now I think that figure would hold true for other existing plants; in fact, a modification may be a higher percentage. So it is a substantial cost that the consumer would encounter. Its our position that that should not be done unless there are significant benefits and there are lower cost options or strategies to be followed such as the use of low-sulfur coal by coal washing. Plus there is a new technology. In addition to capital operating costs, you have a loss of power from the unit, which is an additional cost. And quite likely, and this is the point I make in my statement, that we could not modify our existing plants, all the older plants, because of their location and physical constraints and it could result, very likely, in an early retirement which would reduce he number of coal-burning plants and that's certainly not in the interest of our customers.

Senator **Warner**. What would the impact be on customers? Do you have a couple of hypotheticals?

Mr. **Davis**. We expect the cost would have to be passed on to the ratepayers in terms of higher electric bills and I think we need very carefully to make sure the customer is aware and the consumer is aware that in each of these decisions, he would be faced with a higher cost for his energy both directly through his electric bill and also through the products that he buys that are manufactured and supplied, too. So the costs would be significant to the consumer, too.

Senator **Warner**. That's a very helpful contribution. Thank you. We will now hear from Mr. Upmeyer, vice president of Electric Fuels Corp. at St. Petersburg, FL.

STATEMENT OF ERNST A. UPMEYER III, VICE PRESIDENT, ELECTRIC FUELS CORP.

Mr. **Upmeyer**. Thank you, Mr. Chairman. I appreciate the opportunity to be here today. I represent Electric Fuels Corp. which is a wholly owned subsidiary of Florida Progress, a holding company that also owns Florida Power Corp., the second largest utility in the State of Florida. Electric Fuels was established to mine, acquire, and transport coal for Florida Power and others. We have a mining project in Lee County, VA, as a matter of fact. We also are involved in the research and development area of new fuels technology. We've reflected a number of times today on the impact of the oil embargo and subsequent rise in the prices. At that time, Florida Power Corp., about 90 percent of its generation was related to imported oil. So you can imagine the impact on the customers of Florida Power. In 1978, in order to mitigate some of the effects of that increase, Florida Power made the decision to convert two of theirt oil-fired units to coal. Prior to that time, they conducted a test to fire an ultra-fine coal-oil mixture in a 380 megawatt Crystal River Unit 1. This was the first firing of coal-oil mixture in a major utility boiler. We were successful with that test and we have subsequently formed a partnership called COMCO that is composed of the Dravo Corp. of Pittsburgh and the A.T. Massey Coal Co. of Richmond. In order to further reduce the dependence on foreign oil, Florida Power made the decision to convert their Barto Unit No. 1 to permanently fired coal-oil mixture. The first firing of that unit took place in May of 1982 and, since that time, we have burned over 800,000 barrels of coal-oil mixture in the plant. The unit currently operates and meets all the environmental standards. Prior to conversion of the plant, we anticipated a number of problems with coal-oil mixture. First, of course, was the regrading problem and there was none on which we began to fire the unit. We we concerned that there might be a problem of settling with the coal in the storage tank. Over a 1-year period, we've had no significant settling in either the tanks at the plant or where we manufacture the coal-oil mixture. We we concerned about transporting the material. We moved it across Tampa Bay from the location where its made to the Barto plant in 15,000-barrel barge loads and we've had no significant problems in the transportation area. Another area where we anticipated problems was in wear and erosion. Over the past year, we have had one significant problem and that has been erosion of the burner tips in the area where the fuel is projected into the boiler. Florida Power has conducted an extensive research program on those burner tips and we now have a design that we think is adequate to keep erosion at an acceptable level for commercial operation. We we concerned about the possibility of slagging and fouling of the coal ash in the boiler and also the difficulties of catching the coal ash in an electrostatic precipitator. Neigher of those concerns have proven to be true. Most of the ash comes out of the boiler in the form of fly ash and its been an excellent quality ash that we have been able to sell for use in the cement industry.

We've achieved a number of things with this project. We've built this first commercial sustained commercial coal-oil mixture plant. We've established the transportation, storage, handling, and firing of the unit. But I'd like to comment briefly on the economics involved and that's really the bottom line.

In 1981 when the conversion of Barto was started, Florida Power was buying oil for about $29 a barrel. We had every expectation at that time that the cost would go significantly higher. The breakeven point for COL on and a used equivalent oil barrel of oil basis is in the neighborhood of $27 a barrel. Florida Power is currently buying oil at about $26 a barrel. What we haven't achieved with this project is economic success in today's oil market. Unless you are willing to attribute some value to the back out of foreign oil.

COMCO since that time has developed a product called ready-coal. This is a ready to fire, dry, finely pulverized coal produced in the central preparation facility, delivered to the user's site and burned using standard coal-firing equipment in oil or gas designed boilers, dryers, and kilns. We've made this material, we've handled it, we've stored it and demonstrated the transportation feasibility by moving it in a tank truck from Tampa to Pittsburgh. The benefits of this material are its a lower cost product than coal-oil mixture or coal-water mixture, it requires lower capital cost and on site coal systems and it eliminates the operating burden of coal handling and pulverizing plus removing the environmental impact of open coal storage at the user's site. We see a great potential for beneficiation of coal in this process since the size and consistency is so small. We are currently involved in negotiations with a large industrial user for the conversion of their facility to burn ready-coal which will demonstrate the commercial viability of this fuel. Florida Power is also studying the conversion of at least a portion of the Barto unit to burn ready-coal to improve the economics there. Depending on the particle size required for various applications, the as-used bread-even cost for ready-coal on an oil equivalent basis ranges from about $20 a barrel to about $25 a barrel. Electric Fuels, Florida Power and COMCO have been in the forefront of the development of alternative fuels for some time. From our experience, we've discovered a number of areas where government impacts are working and can have a decided effect on the future of alternative fuels.

In the environmental area, there are three points. There's a need to streamline and simplify the permitting required for this type of activity. The second is that there needs to be a provision in the environmental laws to allow for exceptions to current regulations during the development of these technologies up through the demonstration phase. The risk to the environment is measured by the benefit to the country if these things are fully explored. And third, its important not to penalize environmentally those plants that convert to coal based fuels. Conversion shouldn't trigger the requirement to reduce emissions below those currently permitted at the plant site.

In the area of regulation, there are two points. One is the need to reduce the impact of State and Federal agencies on the nonregulated diversification of utilities. The efforts in the area of fuel technology are risky and they deserve a commensurate reqard, not limied to the utility rates of return. Second, we need to limit what I call hindsight regulation. The Florida Public Service Commission is currently preparing to decide whether or not they will allow the passthrough in the fuel adjustment clause of the difference between the cost of coal-oil mixture and the cost of No. 6 oil at Barto. Should the recovery of such differential resulting from what we didn't foresee in the way of market changes not be allowed then the attitude of utilities toward taking the risk of using new coal-based fuel is going to be highly negative.

Finally I'd like to make a point about Government support of new projects. The Government really should support strongly those projects that have real economic viability. For example, Electric Fuels has recently done a coal transportation study for NASA. In this study, we evaluated the movement of coal to Florida fuel—a gasifier that would provide electricity, steam and off gases such as nitrogen and hydrogen that are essential to the Space Shuttle Program. Its my strong belief that Florida Power and probably many other utilities will never build large coal-fired central station generating plant. Instead they're going to abandon the search for marginal economies of scale, they're overwhelmed by regulatory uncertainty, by financing uncertainty, by environmental uncertainty, and load growth uncertainty and they're going to turn to smaller modules of generation. My guess is that this capacity is likely to come in the form of 200 megawatt combined cycle units tied to coal gasification as a fuel source. If this guess is correct, information gained from a Federal project such as this NASA gasifier would be invaluable in making this change in the direction of sound commitment for both the utility and its customers.

I appreciate the opportunity to share these thoughts. I think we're facing the coal industry and the utility industry and a time of tremendous change such as this will help us all to meet the challenges of that change better.

[The prepared statement of Mr. Upmeyer follows:]

PREPARED STATEMENT OF ERNST A. UPMEYER III

Mr. Chairman, my name is Ernst A. Upmeyer, III. I am Vice President of Electric Fuels Corporation. Our corporate offices are located in St. Petersburg, Florida; Electric Fuels (EFC) is a wholly-owned subsidiary of Florida Progress Corporation, a holding company that owns, in addition to Electric Fuels, Florida Power Corporation--the second largest electric utility in the State of Florida, serving some thirty-two counties within the State. Electric Fuels was formed to acquire and transport coal for the use of Florida Power Corporation, to engage in the provision of transportation services and the sale of coal to others, and to participate in the research, development and commercialization of new fuels technology.

Among our activities we are partners in a venture that is currently mining coal in Lee County, Virginia. We own coal reserves in Virginia, Kentucky, and West Virginia. We are a partner in a large bulk materials handling terminal on the Mississippi River south of New Orleans, and we have a fleet of ocean-going tug/barges that transports coal from the mouth of the Mississippi to the West Coast of Florida. As a result, we represent many interests.

However, in my testimony today, I should like to represent only two interests: the coal industry and the some three and a half million people living in the Florida Power service territory.

It is difficult to remember in these days of a depressed economy and a glut of oil, the effects of the oil crisis of the 70's. The gas lines, the tripling of energy prices, all combined to have a devastating impact on consumers. Particularly, those in the Florida Power service territory who were retirees on fixed incomes. Yet this is precisely the time to remember, to plan and to prepare for the time of shortage and rising prices that surely will come again.

Florida Power Corporation, at the time of the oil embargo utilized imported oil for about 90 percent of its generation. During the oil crises, Florida Power made the decision to convert two large generating stations at Crystal River on the Gulf Coast of Florida from oil to coal.

In 1978, prior to the conversion of those units, Florida Power fired an ultrafine coal/oil mixture in the 380 megawatt Crystal River Unit No. 1. This was the first firing of coal/oil mixture in a large utility boiler.

Based on the success of those tests and to develop and commercialize the technology, a partnership named COMCO was formed between EFC and the Dravo Corporation of Pittsburgh, who had done the engineering for the tests. Later the Partnership was expanded to include the A. T. Massey Coal Company of Richmond, Virginia.

In an effort to further reduce dependence on imported oil, Florida Power made the decision to convert the Bartow Plant Unit No. 1, just north of St. Petersburg on Tampa Bay, to burn coal/oil mixture on a fulltime commercial basis. This 125 megawatt unit first began burning coal/oil mixture May 20, 1982. To date, over 800,000 barrels of coal/oil mixture have been burned in the plant. The fuel is a mixture of 46 percent coal, ground to 98 percent through 325 mesh, with an average size of 22 to 24 microns. At this size the coal is similar in consistency to talcum powder. The balance of the fuel is No. 6 oil without any additives or water.

The unit currently operates without any derating and meets all the environmental standards. The fuel supply for Bartow is prepared by COMCO at its Port Sutton Plant in the Port of Tampa on Tampa Bay. It is shipped by barge across the Bay in 15,000 barrel loads. The COM is stored in a 150,000 barrel tank at the plant site.

Prior to the conversion of the plant, we anticipated a number of problems with the use of coal/oil mixture in a utility boiler.

First and most important was the possibility of a derating of the unit's capacity. By comparing tests that were conducted before the conversion, while the unit was still burning oil, with tests conducted after the conversion, we discovered that the boiler efficiency on oil was 88.55 percent while the boiler efficiency on coal/oil mixture was 88.59 percent.

We were concerned that there might be a problem of settling out of coal in the storage tanks. We have found, after more than a year of operation, no significant settling either in the Bartow storage tank, which is mechanically agitated, or in the storage tank at Port Sutton, which has no agitation.

We were concerned, also, about the transportation of the material by barge. So far, we have transported from Port Sutton to the Bartow Plant 890,000 barrels of COM. The barge was recently inspected, and we discovered no significant settling in the barge and no significant erosion of the fittings or piping for handling the coal/oil mixture.

Another problem area anticipated was wear and erosion of the pumps, pipes, and fittings of the plant. This did turn out to be a minor problem and we had to replace three fuel pumps with pumps of a different type. That replacement occurred early in the program. The plant has just been returned to service after an annual maintenance outage in which we thoroughly investigated all of the components of the system for wear and erosion; and, what erosion there was, with one exception was described as minimal. The exception is the burner tips which project the fuel into the furnace. These tips have been a continuing problem from the standpoint of erosion. Florida Power has conducted a long research program to test different configurations of burner tips and different materials and now feel that they have a burner tip of a design adequate to keep erosion at an acceptable level for commercial operation.

We were concerned about the possibility of slagging and fouling of coal ash in the boiler and both of these characteristics have been found to be minimal at the end of a year's operation.

We, also, worried about the handling of the ash from the coal in the mixture and the ability to capture the ash in an electrostatic precipitator. One of the surprising results of this project has been that there was virtually no ash falling down in the bottom of the boiler. This is a positive and significant feature for the combustion of this material in typical gas and oil design boilers where the bottom of the boiler has very little room to collect ash. Most of the ash reported out of the furnace as fly ash. It appears to be a very high quality ash, easily captured by the electrostatic precipitator, with less than one percent carbon carryover. The ash, based on our analysis, appears to be a product that is highly salable for use in the cement industry.

WHAT HAVE WE ACHIEVED WITH THE PORT SUTTON/BARTOW PROJECT?

(1) We have the only coal/oil mixture plant operating on a sustained commercial basis,

(2) We have successfully demonstrated the commercial scale application of the ultrafine grinding of coal,

(3) We have established the routine barge transport of COM,

(4) We have completed the first permanent full utility boiler COM retrofit,

(5) We have proven the viability of large-scale COM storage,

(6) We have demonstrated the highest sustained coal concentration in COM burned in a utility boiler and,

(7) We have the first electrostatic precipitator operating successfully on coal/oil mixture.

I'd like to comment briefly on the economics of this project. In 1981 when the conversion of Bartow was started, Florida Power was buying oil for approximately $29 a barrel, and we had every expectation of that cost going much higher.

The breakeven point for COM on an "as used" equivalent barrel of oil basis is in the neighborhood of $27 a barrel. Florida Power Corporation is now buying oil at about $26 a barrel.

What we have NOT achieved with this project is economic success in today's oil market unless you are willing to attribute value to the backout of imported oil.

WHERE DO WE GO FROM HERE?

COMCO has developed a product called REDICOAL. This is a ready to fire, dry, finely pulverized coal produced in a central preparation facility, delivered to the user's site and burned using standard coal-firing equipment in oil or gas designed boilers, dryers, and kilns.

Our development of this product was based on experience acquired in Germany where a company has been producing a similar product in successful commercial operation since 1978. This product, based on brown coal, is produced at a rate of two to three million tons per year, supplying cement plants and industrial dryers.

We have made this material, handled it and stored it. We have demonstrated transportation feasibility by shipping the material in a tank truck from Tampa to Pittsburgh. We have burned it satisfactorily in a boiler. The benefits of this material are that it is a lower cost product than coal/oil mixture or coal/water mixture. It requires a lower capital cost than on-site coal systems and eliminates the operating burden of coal handling and pulverizing plus removing the environmental impacts of open coal storage at the user's site. We also see a great potential for the beneficiation of coal in this process.

We are currently in negotiations with a large industrial user for the conversion of their facilities to burn REDICOAL as a demonstration of the commercial viability of this fuel. Florida Power is also studying the use of REDICOAL to decrease oil use and, thus, improve the economics at Bartow. Depending on the particle size required for various applications, the "as used" break-even cost for REDICOAL on an oil equivalent basis ranges from about $20 per barrel to $25 per barrel.

Based on our work to date and these types of economics, we believe REDICOAL will have a significant place in the energy future of this country and represent a substantial coal market for the future.

Electric Fuels Corporation, Florida Power Corporation, and COMCO have been in the forefront of the development of alternative fuels for some time. From our own experience, we have distilled several areas where government impacts our work and can have a decided effect on the future development of new coal-based fuels.

FIRST, IN THE ENVIRONMENTAL AREA THERE ARE THREE POINTS:

(1) There is a need to streamline and simplify the permitting required for this type of activity. Time is often of the essence.

(2) There needs to be a provision in the environmental laws to allow for exceptions to current regulations during the development of these technologies up through the demonstration phase. The potential for temporary damage to the environment is small compared to the major benefits to the economy of the country.

(3) It is important not to penalize environmentally those plants that convert to coal based fuels. Conversion should not trigger requirements to reduce emissions below those currently permitted at the plant.

SECOND, IN THE AREA OF REGULATION THERE ARE TWO POINTS:

(1) There is a need to reduce the impact of state and federal agencies on the non-regulated diversification efforts of utilities or holding companies.

Diversification, particularly in the fuel development area, has a high element of risk and deserves higher rewards than the limited utility rates of return.

Burdensome reporting requirements such as may come out of Senate Bill 1174 may overwhelm a small company intent on developing a new fuel technology.

(2) We need to limit "hindsight" regulation. The Florida Public Service Commission is currently preparing to decide whether or not they will allow the passthrough, in the fuel clause, of the difference between the cost of coal/oil mixture at Bartow and the cost of No. 6 oil.

Should the recovery of such differential, resulting from unforeseen market changes, not be allowed, the attitude of utilities toward the risk of using new coal-based fuels would certainly be highly negative.

AND FINALLY, A POINT ABOUT GOVERNMENT SUPPORT OF NEW PROJECTS:

The government should strongly support those projects that have real economic viability.

As an example, Electric Fuels has recently done a coal transportation study for NASA. In this study we evaluated the movement of coal to Florida to fuel a gasifier that would provide electricity, steam, and gases such as nitrogen and hydrogen that are essential to the space shuttle program.

It is my strong belief that Florida Power and probably many other utilities will never build another large coal-fired central station generating plant. Instead they will abandon the search for marginal economies of scale. Overwhelmed by regulatory uncertainty, financing uncertainty, environmental uncertainty, and load-growth uncertainty, they will turn to smaller modules of generating capacity. My guess is that this capacity is likely to come in the form of 200 Megawatt combined cycle units tied to coal gasification as a fuel source. If this guess is correct, information gained from a federal project that seems to be as economically viable as the NASA gasifier would be invaluable in making this change of direction a sound commitment for the utility industry and its customers.

I appreciate the opportunity to share these thoughts with you today. I believe the coal industry and the utility industry stand on the threshold of major changes in the way we use and supply our products and services. A forum such as this allows us to share ideas that will benfit both industries and ultimately benefit the most important interest I represent--
OUR CUSTOMERS.

Senator WARNER. Thank you very much, you've been very helpful.

We now have Kenneth Crews, managing director, Lehman Brothers, New York City; Kenneth Hollister, vice president, Dean Whittier Reynolds, New York; O. J. Peterson, vice president-treasurer and chief financial officer of Viriginia Electric & Power Co. Mr. Crews and Mr. Hollister, since a number of us have been since 10 o'clock without the benefit of much outside communication, what's the market doing? [Laughter.]

STATEMENT OF KENNETH S. CREWS, MANAGING DIRECTOR, LEHMAN BROTHERS

Mr. CREWS. Senator, I was interested in your comment about bias to one of the other speakers, and maybe I ought to get my bias on the table at the beginning. I've been a partner at Lehman Brothers for a few years, I've been with Lehman Brothers for 10 with two other partners who are in charge of managing all of the corporate finance for the electric utilities, the gas distribution companies, the gas transmission companies, the mining companies, the oil and gas companies, and the railroads so we do represent a certain potpourri of conflicting economic interests, but my personal bias is that Lehman Brothers makes more money in vibrant economies and good markets and I definitely have a bias toward making more money.

Senator WARNER. We're all for that.

Mr. CREWS. The reason I will try to be just as brief as I can—I think a typical Wall Street view of this kind of question is an overriding confidence in our ability to analyze world and national economic problems and that perhaps its only overshadowed by Washington's belief that it can resolve those problems. Before getting into whether the financing can in fact happen, the best thing is to take a step back and say just what is the problem. You've heard a lot of facts and figures, no question about it, coal demand is down. Though coal demand is going to stay relatively flat, it was slightly up for a fairly significant period. I think the reasons for that are interesting and have a lot of bearing on what we are talking about today. First, and foremost this country, to its surprise every 3 or 4 years, realizes that there is, in fact, and elasticity of demand. Electric energy costs have been up, the economy has been down and without too much ado the marketplace has adjusted to that. Coal demand is signficantly down. It is a true, clear economic fact. It is effecting the gas prices, it is effecting the oil prices. Lower gas and oil prices are having a continuing effect on coal demand and increased electricity demand. The increased cost for pollution control exacerbates that, and the continued uncertainty about transportation costs further excerbates it. I think the important thing about those factors, the 3 or 4 pertinent factors of probably 25, that we could talk about if we had more time is, that in the same way these are market created phenomena, they will be market corrected phenomena. I think that the tendency to try to correct these problems which is the marketplace working, is a mistake. The second area for getting pure economic reasons of why coal demand is down and why is it likely to stay down for a while is unquestionably the regulatory situation. Here again, there has since 1973 been there seriously conflicting directives about what the prime users in the United States—the utility industry—should be burning in their boilers. On Wall Street, I would make the point—it is largely Wall Street's view and certainly my firm's view—it doesn't matter which energy fuel country mandates that we use coal, nuclear power, oil, gas. Being from Oklahoma, I have a bias on that, but it really doesn't matter. Maybe the smartest thing we can do would be let the lowest cost determine which is used. That's all the marketplace needs to know. It doesn't need help on choosing which product to use it just needs to know it would be very cheap.

Senator **Warner**. Let me comment on that. You've raised a very valid point. In other words, we've changed direction and it comes from Washington. The practical matter is our political system is such that they are changing faces in the Congress and even in the administration. And the famous saying, "What Congress can do, it can undo the day following," which frequently we do. So I think you are going to have to accept that as part of the political system that Churchill once observed is worst on Earth but he didn't now of any better one.

Mr. **Crews**. That's a fair comment. I just want it to be clear that if New York is heard at all, we sometimes only listen to ourselves, that in that constant battle to do good things for the economy that it might be better to do nothing at all. My firm is still managed by people who have, in the past, been Secretary of Commerce, of Defense, Director of the CIA, there is a certain Washington component. And without pretending to be unsophisticated about the greatness that has contributed to our economy, I think, in all fairness, there is some wisdon to the fact that the economy, when all is said and done, has a very rapid, self-adjusting capability within itself.

There are there reasons why coal demand is down. First, and most important, is economic. Second, regulatory. And third is what we call technical. That is simply that companies right now are very reluctant to make large new capital expenditures for new projects which are uncertain and technical risks are great and demand is low. We should not be investing right now in a lot of these technologies because they aren't profitable. So I would hasten to add, let's try to correct coal demand problems through trying to take one of the self-adjusting components out of our economy which is the economic projects, for projects with economic proven future have always gotten financed in this country.

Being very brief, I'd like to just quickly split the future, as at least my firm and the energy partners that I work with see it regarding this industry and coal demand. I should have added that we are investment banker for eight of the largest coal companies in the United States so it is an important question to us. The question is in the short-term roll, What can Government do, how can it assist in happening out there in the economy? The truth of the matter is, in the near term very little can be done that would be profitable for coal demand, coal consumption, in this country. The truth of the matter is that the goal that we would like to see is not to create a certain degree of cost effectiveness just for coal, but just create a market that's cost compeitive. One of the things that is important right now, we probably should not ever have had it in this country, is tax exempt financing. It doesn't make intellectual sense going forward but we certainly would be in a mess and have a massive problem if we tried to eliminate it now. The system has accommodated it and the markets are large and sophisticated. I would only suggest that as deficits continue to rise or at least stay large that one of the areas that's going to be interesting and try to save Treasury dollars, is going to be cutting back on tax financing intellectually. I find it hard to argue against that, but practically it is a large sophisticated necessary market now. To cut back on that tax-exempt financing particularly in light of what are going to be massive new costs associated with acid rain would be a disaster for coal consumption in the United States. Please think in terms of consistency in the energy use policies. I don't know of any practical, rational, economically grounded, politically sophisticated person, except some of my railroad clients, who do not support the belief that this country cannot afford to look at economic places to create coal-slurry pipelines. It is safe, it is quick, it is cost effective and it is one of the key components for people making 10- and 20-year decisions right now about what is going to be the fuel for their future. Is it going to be the kind of a problem that when there is an opportunity to build a relatively cheap 300 or 400 mile pipeline system that will dramactically alter their costs, if they cannot envision an economy where that can happen it is going to have a hell of a lot of bearing on what they decide to use for their base fuel. I might point out that merely the threat of building coal-slurry pipeline has done amazing things to railroad pricing. I think that we, in this economy, despite my four major railroad clients, are not in business of subsidizing their continued existence. They are quite capable of defending themselves in the cost competitive marketplace. But to penalize the economic system and coal use in this country by not allowing a pipeline system is a crime.

Senator **Warner**. I'm going to get you a copy of that book.

Mr. **Crews**. The other encouraging thing about that, that's the first time I've heard a Washington & Lee person refer to a book. [Laughter.]

I think, very quickly, in the longer term situation of this problem there's no question—massive new cost-effective technology are coming whether its coal gasification, liquifaction, combustion, whatever type, its coming and its important. It will be cost effective. There is going to be a time in the very near future when Government can be the catalyst for making it happen, much as it was the catalyst for returning Chrysler Corp., to solvency. I would only hope that catalytic process was in the form of the most market related, whether it is tax credits, loan guarantees, or price support. The system should be directed toward making sure the marketplace was costing that particular technology. If its not, we are wasting money. I think there is also clearly a place for those people who say, "We are going to make a grant and we're going to build a certain plant or a certain technology." And that's going to be a cost that should be borne by the taxpayers of this country; its the right thing to do. Its R&D on a necessary scale, just like any investor-owned corporation in America must do. I don't think that we should be ashamed of doing that. I think what happens, though, is there is a tendency to try to build a system that allows too many options. If we are on an on-going basis and are going to be trying to subsidize an industry, let's do it with as much help from the marketplace as we can. But short of that, I don't think anyone will argue that there's nothing to be ashamed about serious, genuine, costly R&D. On Wall Street there ultimately is only one place to look for those kinds of dollars and that's the Federal Government. We are invariably skeptical of companies or Government officials who try to pretend that some of those expenditures are going to be economic. They aren't, let's face it. And as long as they're not economic and we recognize they're not going to be economic, most R&D, in the short term, is not economic; we have nothing to apologize for.

So quickly summarizing, its our view that the coal industry is in for a period of some shocks, there's no question about it. We can only hamper that return by trying to solve problems in the near term which are going to rectify themselves and are ignoring some of the problems that are in the longer term, which we put in the 3- to 5-year category, that need to be dealt with right now. Thank you.

Senator Warner. Thank you very much.

STATEMENT OF KENNETH HOLLISTER, VICE PRESIDENT, DEAN WHITTIER REYNOLDS

Mr. Hollister. Thank you very much, Senator, its a pleasure to be here today. My background, for approximately 20 years, was in securities research in regulated industries as opposed to corporate finance where the actual financing is done. Four years ago I moved over to the corporate finance side and, since that time, I've learned both religion and finances. But being outside the industry I have a different perspective of what's being said here today, although I agree with much that Ken said.

Senator Warner. You do or do not agree with him?

Mr. Hollister. I agree with him. I agree with most of what he said. It seems to me that if financial incentives are to be sought they're very easily attained. There's a word, its called problems. Unfortunately, a move from a position of financial concern to profit is not always so easily achieved. Further, based on my somewhat limited knowledge of the coal industry and what I've heard here today I would say that from a financial standpoint they've got their work cut out for them. On the other hand, the potential for the future use of coal be it for conversion fuel, creation of synthetics of others, appears to provide a basis for investment that could provide for growth of the industry over a period of time. If, as an outside observer, I hear a weakness in your position, it is the fragmentation I think I see between the producers, the processors and the users. All have the same end result as a goal but the degree of unity expressed as to how this is to be achieved is nowhere near its term. During the course of the day, for example, I've heard all sorts of numbers as to relative costs and advantages compared to competitive fuels. I had no sense that they were fully comparable or even comparable and there is nothing the financial community likes less than that sort of uncertainty. Further, I think with the exception of Mr. Wolfe and Mr. Henderson, the opinion was expressed that Government funding was required for this project or that because profitability was uncertain. Again, this does not fill the financial group with confidence of the potential for reward of its investment.

The point that I would make is that the coal industry with all its component parts is competing for capital and as any beady eyed banker will tell you, capital wants to earn its worth. A number of your R&D programs sound promising and some are being privately funded. Some will succeed leading to further investment. If, however, R&D is to be undertaken in order to change the Nation's dependence on foreign fuels and it requires unknown and untested technologies, then it must be tax supported. The private markets have other places to go. If the government wants to have existing companies made risk type investment, the way it can be accomplished is through tax appreciation policies even if it does have an effect on the national budget. In order to draw on individual savings similar approaches must be used: Reinvestment programs, possible tax changes on dividends on certain common stock under certain conditions, tax deferral on dividends. All have worked, all have created savings that have been reinvested in industries. So, this is another way of doing it. I would strongly urge that you seek some degree of cooperation within the scope of legally permissible actions and accommodations between the producers, processors and users in the R&D effort, in order the enhance the prospects for your industry. I believe that I agree with Ken, that if there is a plethora of plans none will succeed and that if there is a single plan or purpose in using government funds for the fuel industry or the energy industry, fine. Otherwise, let's go ahead and do what we've been doing so well. Thank you.

Senator **Warner**. I address a question to both of you. What would be your posture today with the view in Congress with respect to synfuel?

Mr. **Crews**. I think there are three projects, maybe $5 million of expenditures, that are justifiable and which I would support. I would never have supported anything like $83 billion or even $17 billlion for that kind of expenditure.

Mr. **Hollister**. I guess I take a stronger view. If synfuels is to be looked at as a absolute replacement over a period of time, with the purpose of developing the technology to permit synfuels or its end result product to provide a competitive fuel, over a period of time, I agree that something should be spent. If it is a stopgap to get me so that I don't use foreign oil but I'm going to subsidize fuel for the next 25 years I would have a difficult time with both of those.

Senator **Warner**. All right, thank you. Next is O.J. Peterson, vice president and treasurer, chief financial officer of the Virginia Electric Power Co.

STATEMENT OF O.J. PETERSON III, VICE PRESIDENT-TREASURER, CHIEF FINANCIAL OFFICER, VIRGINIA ELECTRIC POWER CO.

Mr. **Peterson**. Senator, I just wanted to say that I'm with the Virginia Electric Power Co. and I suppose most of the people in this room are familiar with that company. It is the tenth largest electric utility in the United States. It has assets of over $7 billion, it serves 1.4 million customers in 3 states and it encompasses an area in Virginia of 65 percent of the land area and includes more than 80 percent of the population of the State. This is a very interesting panel I'm on. Being a utility financial officer, I am on the side of the equation where you raise the money and you put it to work hopefully for a return; sometimes that's questionable. The utility industry is probably not going to make signficant capital investments in research and development projects of large magnitude. There is a capital investment made by the utility which is research relevant but it generally is relatively small in nature and is not a major source of new innovations and technology to the industry. Most of those new innovations come from the suppliers to the industry such as General Electric, Westinghouse and Combustion Engineering, people like that, who do make R&D investments to produce better products for our industry to utilize in serving the public. Now, when it comes to the financial incentives that could be implemented to allow utilities as consumers of coal to utilize more coal, there are a number of those that have been used in the past and are probably going to be used in the future. Vepco has been involved for years in making pollution control investments and as a result have been able to use most of the Government incentives that have so far been provided. Sam Brown and I, he is the vice president of Vepco who was on earlier, have alluded to conversions that our company has made converting 1,800 megawatts from oil to coal. That cost us something like $280 million to do and we would have done that with or without built in incentives. But I'll have to admit that the government incentives that did exist were helpful. The primary ones that I'm familiar with are investment tax credit, accelerated depreciation or amortization for pollution control facilities and other types of facilities, and tax exempt financing. Actually, those incentives do work and they do cause investments to be made sooner than they would otherwise be made without those incentives. But from my experience that's the only thing they do, because the investments would be made anyway especially when they're investments in facilities that are mandated by Government action. Of the incentives that I've mentioned, the one that we prefer the most is the tax exempt financing. The reason for that is very simple. It has been my experience that most of the time when a Government mandated requirement such as pollution control facilities or acid rain comes along, it generally comes along from companies that can least afford to implement it. As a result, such incentives as tax credits and accelerated depreciation or amortization don't mean a lot because if you're not making any money you're not paying any taxes and the acceleration of depreciation doesn't do anything but build a larger carry forward. So that means taxes and financing of the types of incentives that I'm familiar with is the most popular from the point of view of all companies.

The coal consumers, to me, are not the only source that can use tax-exempt financing. With or without acid rain legislation, the utilities will burn more coal and more coal will be produced if the incentives go not only to the consumer but also to the producer. The Internal Revenue Service and its regulation of the Congress' intent to allow pollution control facilities to be financed on a tax-exempt basis, the Internal Revenue Service has determined that that only includes the consuming end not the coal production system. They do not allow the tax incentive of tax-exempt financing to be utilized financing, investments at the producers end. To me, that is ridiculous because there is no better way, in my opinion, to clean up coal, to make a better product that's delivered to the consumer and to leave pollution where it was originated, in the ground and to clean the coal at the mine and deliver a lower ash, lower sulfur product to the consumer and not be required to build expensive facilities at the consuming end to remove something that could have been removed at the producing end. The final reason I think tax-exempt financing should be extended to the entire coal producing system to include the financing of coal cleaning facilities, the financing of coal transportation faculities even including coal slurry pipelines, if those are allowed, and the financing of coal pollution controlling facilities at the consuming end of the coal transportation system.

The only other thing I have to add, Senator, is you asked one of the utilities a question about how much money they thought it would cost the consuming public to implement acid rain legislation. Our engineers have determined that in 1982 dollars it would cost about $1.2 billion to put scrubbers and retrofit on all of our older units to control acid rain. Thank you.

Senator WARNER. What does that mean to the average customer?

Mr. PETERSON. A round figure, $5.18 a month.

Senator WARNER. Mr. Crews, I was interested in the observation of Mr. Peterson in the tax exemption in the financing of the coal cleaning process. Would you have some observation on that?

Mr. CREWS. I hate to admit it to Jim, I think its a good idea.

Senator WARNER. You do?

Mr. CREWS. Yes, I do.

Senator WARNER. Do you think we can carve that piece of the industry out for special treatment and it would be acceptable in the public domain?

Mr. CREWS. In all honesty, as Jim pointed out we already have in the sense that it is. Its now public policy or is soon to become clear public policy that we are going to insist on cleaner coal being burned. If we can control the problem cheaper at the mine level, I think its in the national interest to do that.

Mr. PETERSON. Another thing, Senator, if I might add?

Senator WARNER. Yes.

Mr. PETERSON. A number of small coal producers came forward to build their own coal cleaning plants at the maximum present cost of money. In my opinion, the government gave us this cost of money so, in my opinion, it makes sense for the government to allow 50 percent of that cost, actually to be borne by the government by allowing tax exempt financing to those small businesses.

Senator WARNER. You mean indirectly its a deficit?

Mr. PETERSON. Yes, I do.

Senator WARNER. Gentlemen, you've been a very interesting and provocative panel. In fact, just what we needed after lunch. Thank you so much and have a safe journey back.

We now have our final panel and that will be Charles Anderson Assistant to the Senior Vice President for Exporter Credits, Guarantees and Insurance, Export-Import Bank of the United States; Mr. John Hardy, Jr., Deputy Director of Trade and Development Program, International Development Cooperation Agency; Joseph J. Yancik, Director, Coal Export Staff, International Trade Administration, Department of Commerce; Charles Schotta, Deputy Assistant Secretary for Arabian Peninsula Affairs, Department of Treasury; and Eugene Lubarsky, vice president, business development, Methacoal.

STATEMENT OF CHARLES W. ANDERSON, ASSISTANT TO THE SENIOR VICE PRESIDENT FOR EXPORTER CREDITS, GUARNTEES AND INSURNACE, EXPORT-IMPORT BANK OF THE UNITED STATES

Mr. ANDERSON. Senator, I appreciate the opportunity to testify before the subcommittee and this hearing today. What we do is attempt to insure that the U.S. exporter is on an equal footing with his overseas counterparts. Also along with insuring U.S. exports we hopefully keep the employment as high as we can can to maintain the economic base here in the United States. Typically, the overseas counterparts have official support from their governments in their efforts to export. What I'd like to do is describe a number of the bank programs and how they've impacted on coal exports and coal technology exports.

The principal vehicle for assisting in the export of coal is our foreign credit insurance program whereby we provide insurance coverage, which covers the commercial and political risks for a U.S. supplier of coal. Of course, this would be for any type supplier. We operate this program in cooperation with the Foreign Credit Insurance Association in New York which is a joint underwriting association for about 50 private insurance companies. What we do is offer umbrella insurance policies to a U.S. exporter and we will provide cover for commodities such as coal for up to 180 days. Typically, this policy is an annually renewable policy umbrella coverage for all the producer's export sales, world wide, and typically what he'll do is either have discretionary limits under that policy or will request us to approve for him specific credit limits for particular buyers. I would have to say that although this program has been in existence since 1960, we really haven't seen very much demand for assistance in coal until about 1978, 1979, after the most recent oil shock, and those opening opportunities for coal that opened at that time. One thing that we have found is, whereas we are willing to increase a credit term or support terms up to 180 days, coal producers themselves have been fairly conservative wishing to get either cash or, let's say, terms up to 30 days for their coal sales. They have been quite reluctant to break that line, particularly in the Western European market. We have supported a fair number of transactions in the Mediterranean Basin and most recently we've been approached to do $140 million in Brazil. Theoretically, this could do as much as $280 million of sales. The facility itself has just about been put into place and we would expect pretty high utilization of that facility. So under this insurance program I would have to say that over the last few years we have done approximately $340 million of support.

The second area of the bank is what we call our median-term facilities. These are bank guarantee and export insurance facility. Typically these support capital goods sales on terms of 5 years and either one of these programs is open. I would have to say we haven't seen too much business under either one of these.

Perhaps the most well-known program the bank has is what we call our direct credit facility. We provide either direct credits or financial guarantees. for long-term financing of multimillion dollar export of U.S. goods. And here we've seen, I think since 1981, $580 million worth of support for new coal fired facilities or conversion efforts overseas, and the major item here was in Taiwan where we supported two new electric generating facilities, coal-fired, which totaled around $260 million. So the bank is open. We're often referred to as the best kept secret in Washington. I think our support in the last few years has been quite significant and we would certainly wish to continue that.

I believe what you will see in terms of the export of coal itself is that with the particular problems in Latin America and other countries, Yugoslavia, that they'll be continuing the Exim bank's support there. This should keep that market going for some time with U.S. exports. In the other area, given some of the preliminary information for your office, the idea of making interest to link Ex-Im financing with the long-term coal contracts, I must admit, we really have seen very little coordination in this area in the past and its probably a particular area that should be discussed with your staff to see what could be done in order to facilitate the opportunities for a national association to participate with the producers, themselves.

[The prepared statement of Mr. Anderson follows:]

STATEMENT OF CHARLES W. ANDERSON
ASSISTANT TO THE SENIOR VICE PRESIDENT FOR
EXPORTER CREDITS, GUARANTEES AND INSURANCE
EXPORT-IMPORT BANK OF THE UNITED STATES
BEFORE THE
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

Blacksburg, Virginia
Tuesday, August 9, 1983

Mr. Chairman:

I am pleased to be able to join you today to outline the support available from the Export-Import Bank for U.S. export sales, specifically sales abroad of U.S. coal and coal-use technology and equipment.

Our role is to ensure, in cooperation with the private sector, that sellers of U.S. goods and services have available for their export sales financing facilities which are competitive with those foreign sellers are provided through their official government financing agencies.

Eximbank has a variety of programs with which we can support the export sale of coal and coal-related technology. We are open for business in all of these programs for creditworthy sales abroad.

Eximbank's support for exports of U.S. coal has only recently achieved significant levels. Our export credit insurance program, however, has been available to support short-term credit sales for coal since the 1960's. This insurance program consists basically of short-term coverage against commercial and political risks. It is provided in conjunction with the Foreign Credit Insurance Association (FCIA), the private sector participant in our export credit insurance program. FCIA will cover single sales or multiple shipments of coal to a specific overseas customer on terms of 180 days or less. Coal exporters may purchase annually renewable umbrella policies and apply for lines of credit coverage for individual buyers for shipment periods up to one year.

Insurance authorizations for coal sales in just the last 12 months have totalled $343 million. While this support appears modest, coal producers traditionally have conducted their export sales on secure terms requiring letters of credit or cash and have not availed themselves of our program. Most recently, however, world economic conditions have required coal exporters, dictated by their foreign buyers' need for term trade credit, to seek insurance for their overseas sales. Indicative of this need is a recent Eximbank authorization to support $140 million of metallurgical coal to Brazil on 180-day terms. We recently met on June 21 with representatives of the metallurgical coal industry including Pittston, Westmoreland, Massey, Island Creek and Consolidated Coal to respond to their financing needs in this difficult South American market and stand ready to assist in other countries as well.

Now let's talk about capital equipment sales.

We also have available programs to support sales of equipment and services requiring repayment on what we call medium-term (1 to 5 years) and longer term (for big-ticket products or projects which require repayment in longer than 5 years). In the longer term program, Eximbank provides either direct loans or financial guarantees. Since 1980 we have approved $580.5 million to support sales of such equipment as coal fired power plants in Taiwan, Venezuela, and Spain and oil to coal conversion equipment in cement and nickel projects, for example, in the Philippines, Thailand, and Colombia.

Our medium-term insurance and guarantee programs, as well as our medium-term loan program, are available to support more moderate sales of capital goods, usually for amounts less than $5.0 million and for credit terms of 5 years or less.

In summary, Eximbank has a variety of programs to assist export sales that go forward on a commercial basis. These include short-term credit insurance to support the direct sales of single or multiple shipments of steam or coking coal. They include medium and long term facilities to support new or conversion coal burning projects, retrofits for coal oil or coal and water fuels systems, environmental and pollution control equipment, or other enhanced coal technologies.

Mr. Chairman, this is a very short summary of the facilities available at Eximbank to assist the U.S. coal sector sell abroad, and I assure you that we are very much interested in helping these export sales wherever we can.

Senator **Warner**. I think that would be very helpful. Thank you.

STATEMENT OF JOHN V.E. HARDY, JR., DEPUTY DIRECTOR OF TRADE AND DEVELOPMENT PROGRAM, INTERNATIONAL DEVELOPMENT COOPERATION AGENCY

Mr. **Hardy**. I appreicate this opportunity to testify today before you on the Trade and Development Program's efforts to create export opportunities for U.S. coal producers and manufacturers of coal-related equipment.

I would like first to briefly describe the Trade and Development Program and what we do. And then to share with you our efforts in the coal sector.

The Trade and Development Program was created in 1980 as a component agency of the International Development Cooperation Agency to finance feasibility studies and other project planning services for major development projects in the Third World.

We have, basically, two objectives. One is development and the second is to stimulate the export of U.S. goods and services for these many projects that represent markets overseas. In so doing, we seek to assist U.S. firms, primarily engineering firms, because they are the firms that directly benefit from our financing, and through them, U.S. equipment manufacturers and other service firms, in competing against our export competitors so that U.S. firms have access to these export markets and can improve the U.S. balance of trade.

The premise of our program is that by tying our financing with the fact that a U.S. firm must do the feasibility study, we manage to introduce U.S. firms into projects, in the very early stages in foreign countries, thereby increasing likelihood that in the implementation of the project that U.S. goods and services will be used.

Let me now move to our activities in the coal section. Because we are not involved in the actual financing of projects we are forced to rely, in the course of our selection of projects in which we will participate, to rely upon the country's determination of what those priority projects are because we recognize it would be up to the country to determine how they will use World Bank funds or other sources, to which they have access, in terms of financing their projects. In the course of doing this, we have found that coal projects are very high on the list of priorities because they address two issues which are critical to developing countries. One is the burgeoning demand in these countries for energy and the second one is the sharply increasing price of oil. Our activities in the coal area can really be broken up into three distinct areas. First, on a number of occasions we have financed studies examining the economic feasibility of converting existing oil-fired power generating facilities to coal. We have done this particularly in Jamaica and Cyprus. Secondly, we have been involved in financing studies of two projects in Panama which have the objective of promoting the use of U.S. coal in the Pacific Rim region. Lastly, we have been involved with a number of developing countries in encouraging the use of U.S. equipment and mining services in the development of their own coal resources for domestic use.

Let me go into, very briefly, somewhat greater detail on each of these. With regard to the first area, we have financed several studies examining the technical and economic feasibility of converting existing oil-fired powerplants to coal. These have been sector studies which we have made in Jamaica and Cyprus, in particular, and somewhat in Thailand.

In Jamaica, a conversion of power electrical generating units would initially save Jamaica $50 million in foreign exchange annually and further savings would develop each year. If the aluminum companies participated in this project, that savings would be substantially greater. Exports of U.S. coal combustion equipment for the project are estimated in the range from $120 to $150 million. Amount of U.S. coal which we anticipate very well may be used is from $40 to $100 million per year for this project, depending again on whether the aluminum companies participate. This study in Jamaica is presently nearing completion and will constitute a "bankable document" which Jamaica can then use as a loan application to Eximbank, World Bank, or the Inter-American Bank.

In the second area, as we have stated earlier, we have funded the two projects concerning potential use of U.S. eastern coal which can be transported through Panama for use in the Pacific Rim. The first project feasibility study we financed in 1981 concerning transshipment facility across the Isthmus of Panama. It was determined that that project was not economically feasible.

However, another project has evolved out of that concerning a methanol production facility in Panama which would serve a number of uses. EBASCO Services has entered into an agreement with the Trade and Development Program of which we will cofinance a portion of this feasibility study for the $4.5 billion coal gasification/methanol complex. By upgrading coal to methanol, the project will enable U.S. coal producers to compete in the Pacific Rim energy market against fuels from non-U.S. sources, thereby improving U.S. trade balance with Japan and create jobs in U.S. mines, river barge companies, gulf ports, and at U.S. firms which manufacture equipment for methanol. Its projected, there's a very good likelihood that the bulk of that facility would actually be filled on barges along the gulf coast and then barged down to Panama.

The last area in which we are involved concerns our efforts to encourage the use of U.S. engineering services and coal-related equipment in the efforts of developing countries to develop their own coal resources for domestic consumption. Let me underscore here that with regard to these countries, such as the Philippines and Brazil, they recognize that because of the limited foreign exchange that they have that its imperative they move away from oil and that their own coal resources represent a possible means of doing that.

Where the host countries have been enthusiastic in seeking U.S. technology for their development of their coal reserves, we have utilized symposia and followed up our feasibility studies with particular projects to bring the parties together and to try to encourage an increased understanding on the part of developing countries of what U.S. technology has to offer in this area. Brazil is a prime example of this.

We have been working with Brazil at both the Federal and State level, financing studies on the application of U.S. coal utilization technologies. Brazilian coals are of high ash content, and therefore we have looked to underground and surface coal gasification, as well as fluidized bed combustion, as a possible means of using U.S. equipment in the utilization of those resources. We have financed studies in each of these areas. Most recently in Brazil, we have entered into discussions with officials in the Federal Government with regard to supplying U.S. metallurgical coal to Brazil through countertrade arrangements. Currently, Brazil imports some 9 million tons of met coal, of which 4 million comes for the United States. It is possible for the United States to capture the entire Brazilian market for this coal if we can figure out a way of identifying some $500 million in additional Brazilian goods to be sold in the United States or other markets. Trade and Development Program is presently considering financing the feasibility study on this.

Briefly summarized, these are the principal activities in which we have been involved in the coal area. Thank you for the opportunity to present the TDP views.

[The prepared statement of Mr. Hardy follows:]

PREPARED STATEMENT OF

JOHN V.E. HARDY, JR.

U.S. TRADE AND DEVELOPMENT PROGRAM

I appreciate this opportunity to testify today before this Subcommittee on the Trade and Development Program's efforts to create export opportunities for U.S. coal producers and manufacturers of coal-related equipment.

I would like to provide the Subcommittee first with a brief description of the Trade and Development Program and then to share with you our efforts in the coal sector.

The Trade and Development Program was created in 1980 as a component agency of the International Development Cooperation Agency to finance feasibility studies and other project planning services for major development projects in the Third World.

TDP's objectives are twofold--to help countries develop and, simultaneously, to increase the export of U.S. goods and services overseas. TDP identifies and supports development projects throughout the Third World which have been accorded the highest priority in the industrial development plans of the host countries. Because these projects represent important opportunities for the sale of equipment, engineering and management services, and U.S. commodities, the United States's export competitors are extremely aggressive in their efforts to win these projects for their respective firms. TDP seeks to assist U.S. firms in meeting the competition from our export competitors so that U.S. companies have access to these export markets and can improve the U.S. balance of trade.

We believe that TDP financing of feasibility studies of projects of importance to the United States has proven to be a highly effective way to promote both U.S. and developing country interests.

The underlying premise of the Program is that through the provision of TDP assistance during project planning, U.S. firms are given the opportunity to be involved at an early enough stage in projects to encourage subsequent awards to U.S. firms of equipment and services associated with the projects. Thus, by virtue of a U.S. firm performing the feasibility study, the position of U.S. firms as potential participants and suppliers in development projects is significantly improved.

Additionally, TDP co-finances with investors feasibility studies of projects with substantial U.S. export potential in which the investor intends to take an equity interest. If the study concludes that the project is feasible and the investment is made, the investor is obligated to reimburse TDP for its contribution to the study.

The Administration's request of $22 million for TDP's budget for Fiscal Year 1984 reflects its commitment to utilize the TDP program as a critical mechanism of the U.S. Government to assist in the USG's effort to improve our balance of trade. TDP has been successful in leveraging Foreign Assistance Act funds both to help countries develop and to generate exports from the United States. TDP has obligated since FY 1978 approximately $16 million, principally to cover the cost of feasibility studies carried out by U.S. firms on major overseas projects. U.S. firms inform us that they have received more than $500 million in contracts for goods and services as a result of studies financed by TDP.

TDP Coal-Related Activities:

In the course of TDP's efforts over the last several years to find capital projects of high priority to the governments of developing countries, coal projects were readily identified because they represent a solution to two issues critical to developing countries--the burgeoning demand in those countries for energy and the sharply increasing cost of oil. Consequently, TDP has been involved in several coal projects which can be divided into three somewhat distinct activities. First, TDP has financed studies examining the economic feasibility of converting existing oil-fired power generating facilities to coal. We have been involved in projects of this sort in Jamaica, Thailand and Cyprus. Secondly, TDP has financed studies of several projects in Panama which have had the objective of promoting the use of U.S. eastern coal in the Pacific Rim. Lastly, TDP has been involved with a number of countries in encouraging their use of U.S. equipment and mining services in the development of their own coal resources for domestic use.

Let me address each of these activities in greater detail:

Becuase of the great pressure placed on the limited foreign exhange resources of so many developing countries by the skyrocketing price of oil in the last decade, many of these countries have been seeking ways to shift away from oil as their principal source of energy. Accordingly, TDP has financed several studies examining the economic and technical feasibility of converting existing oil-fired power plants to coal. In Cyprus and Jamaica we are financing studies to convert the entire public power system for each of these countries to coal. Jamaica is an excellent example of this type of TDP financed activity.

The conversion of the Jamaica public power electrical generating units from oil to coal would initially save Jamaica $50 million in foreign exchange annually and further savings would develop each year. If the aluminum companies based in Jamaica also switch to coal, the savings could be much greater. Exports of U.S. coal combustion equipment for the project are estimated at $122 million and of U.S. coal at $40 to $100 million per year, depending on whether the aluminum companies convert to coal. Through the use of highly efficient pollution control devices, the coal-fired units would protect the environment even better than the existing oil-burning plants. The study is nearing completion and will constitute a "bankable document" which Jamaica can use as a loan application to EX-IM Bank, World Bank, or the Inter-American Bank.

TDP financed the study at a cost of $450,000. The U.S. firm conducting the study has agreed to reimburse TDP for the cost of Phase II ($300,000) of the study if it wins subsequent contracts for execution of the project. We anticipate that these projects could result in as much as several hundred million dollars in U.S. coal-related equipment and engineering services as they are implemented.

In the second area of TDP's involvement with coal in the Third World, TDP has funded studies of efforts to transport U.S. eastern coal across Panama for use in the Pacific Rim countries. In 1981, TDP financed a study to examine the feasibility of building a coal transshipment facility across Panama to eliminate the need for large coal vessels to go around South America; unfortunately, the study concluded that the economics of such a project could not justify the investment.

However, out of that project evolved another concept, which is now being analyzed, in part with TDP financing. EBASCO Services, Inc. and TDP have entered into a co-financing agreement for the feasibility study of a $4.5 billion coal gasification/methanol complex to be located in Panama. The project would convert 6.6 million tons per year of U.S. high sulfur coal from the Eastern U.S. to methanol, an efficient clean-burning fuel to be used in Japan's new combustion turbine/combined cycle electric generating plants, or blended with gasoline as a transport fuel. By upgrading coal to methanol, the project will enable U.S. coal producers to compete in the Pacific Rim energy market against fuels from non-U.S. sources. It would therefore improve the U.S. trade balance with Japan and create jobs in midwestern mines, river barge companies, gulf ports, and at U.S. firms which manufacture equipment for methanol. It will also produce fertilizers, road building materials and other valuable by-products of coal gasification. EBASCO estimates that U.S. exports from this project could run as high as $1 billion in equipment and services.

The comprehensive study will cost some $10 million, of which TDP is financing $500,000 and EBASCO a similar amount. Congress in the

FY 1983 Continuing Resolution has directed the Department of Energy to contribute $2 million to the study. Negotiations for the remaining $7 million from the U.S. and Japanese private sectors are in an advanced stage. The Japanese firms have organized their own consortium for the project, which will be merged into the U.S.-led international consortium.

The third area of TDP's involvement with coal concerns TDP's efforts to encourage the use of U.S. engineering services and coal-related equipment in the efforts of developing countries to develop their own coal resources for domestic consumption. TDP has financed activities at the request of several developing countries, particularly middle income countries, which recognize that their indigenous coal resources represent a source of energy whose development will reduce the drain on the countries' foreign exchange.

Where the host country has been enthusiastic in seeking U.S. technology for development of their coal reserves for domestic use, TDP has utilized symposia to bring together important host country officials and U.S. Government and business community expertise for short-term technical exchange. The symposia not only help the host country decide how it wants to develop its resources but also educate the decision-makers regarding how U.S. technology and equipment can assist their efforts. Ideally, the symposia also lead to joint ventures or management contracts between the government or local and U.S. firms.

Following such symposia, which have been held in Thailand and the Philippines on lignite and in Brazil on their coal resources, TDP has financed feasibility studies for particular projects to involve U.S. firms and technology in the earliest stages of the project. Brazil is a good example of this pattern of TDP activity.

Reduction of petroleum imports is one of the most significant means by which Brazil can increase its trade surplus and thereby alleviate its severe foreign debt problem. By developing and utilizing its coal, Brazil can substitute domestic energy resources for imported oil. Brazil's coal reserves are estimated at 22 billion metric tons, most of it steam coal. In 1980, Brazil produced only 16 million tons of run of mine coal, a small fraction of its potential.

TDP is working with Brazil at the federal and state level, financing studies on the application of U.S. coal utilization technologies. Brazilian coals are of high ash content, and therefore can be most efficiently used in underground and surface coal gasification, and fluidized bed combustion. Fluor Corporation has completed a TDP-funded Phase I study for a regional coal gasification plant at Mogi Guacu in Sao Paulo, and for the "Southern Cone Energy Network" with gasification plants located in the state of Rio Grande de Sul. Burns and Roe and Foster Wheeler have completed a study of atmospheric fluidized bed combustion for the electric utility in Porto Alegre.

A Phase II study for the "Southern Cone" project will be necessary and has been requested by the Brazilian Ministry of Mines and Energy. TDP will consider funding the Phase II in FY 1984. Meanwhile, TDP has sponsored a visit of experts in U.S. underground coal gasification to determine whether Brazilian coals are compatible with this technology and to assess the economic priority as between underground and surface gasification. The initial findings of the U.S. team indicate there is a good match between Brazilian coal and U.S. underground gasification methods. Our competitor in Brazil for underground gasification is the Soviet Union. We were able to demonstrate conclusively to the Brazilians that U.S. underground gasification technology is markedly superior to that of the U.S.S.R. It is probable that TDP will finance a feasibility study on underground coal gasification in FY 1984.

In a recent mission to Brazil, the TDP representative also discussed with high officials of the Ministry of Mines and Energy the prospects for supplying U.S. metallurgical coal to Brazil through countertrade arrangements. Currently, Brazil imports some nine million tons of metallurgical coal, of which four million come from the U.S. It is possible for the U.S. to capture the entire Brazilian market for this coal if U.S. and Brazilian trading companies can identify some $500 million in additional Brazilian goods to be sold in the U.S. or other markets. TDP expressed interest in financing the feasibility study for such an arrangement and we expect a Brazilian request for the study in the near future.

Briefly summarized, these are the principal activities in which TDP has been involved relating to coal. If the Subcommittee has any questions, I will be pleased to try and answer them. Thank you for the opportunity to describe are activities in this sector.

Mr. **Sindelar**. Mr. Hardy, you mentioned a countertrading, that is something that is becoming more and more the vogue in international trading activities because of the currency situation that exists, the rising dollar, and how that effects our ability to trade in the markets. It is also something that is very rarely understood currently. Could you explain how the concept of countertrading works?

Mr. **Hardy**. I think it's a fairly common practice in the Eastern European countries but most recently I think its been given new emphasis by particularly the Latin American situation in which, because of their credit situation and their lack of foreign exchange, they have entertained the idea of basically a barter arrangement whereby rather than giving the U.S. exporters whole dollars they will give that exporter Brazilian goods which the exporter then has to turn around and use himself, or more likely, turn around and sell to others to obtain the dollars.

Mr. **Sindelar**. So there is a degree of sophistication that is needed to be developed to be worked into this idea of countertrading aspects?

Mr. **Hardy**. Absolutely, a large scale countertrading barter arrangement such as has been proposed by the Brazilian Government becomes tremendously complex as they try to move a great variety of goods, possibly to a wide variety of countries in order to sell them.

Mr. **Sindelar**. This question is addressed to Mr. Anderson. The question has come up of how the credit worthiness of a nation will affect loan agreements. Specifically it has been brought to coal producers attention for U.S. lending institutions to loan in the export market, the country should be credit worthy before credit insurance can be given, possibly the loan arrangement will not be able to be done. And yet you are talking about Brazil in both TDP and in your organization as somewhat worthy of receiving credit investment opportunities. Isn't Brazil a credit risk? And how do you differentiate between credit worthy countries? For a coal supplier or coal technology person to be involved in this, what should he be looking for in credit worthy opportunity?

Mr. **Hardy**. I think what we look at is—you look at the long-term prospect for a certain country. Brazil obviously has a different problem from other countries and we view it as a role which Eximbank can fill to be an intermediary, the facility which provides U.S. exporters and the banking community to stay involved in. So we don't see a particular problem in that. In other words, we've looked at it and we say in the long run the Brazilians will straighten out the situation and the prospects of doing business down there are quite good. At the moment it's a little difficult. You can't expect the private sector to go in, but in the long run we expect it will be all right.

Senator **Warner**. We will now proceed to Mr. Yancik.

STATEMENT OF JOSEPH J. YANCIK, DIRECTOR, COAL EXPORT STAFF, INTERNATIONAL TRADE ADMINISTRATION, DEPARTMENT OF COMMERCE

Mr. **Yancik**. Senator, in the light of its been a long day.

Senator WARNER. Your testimony is very important. You've been patient and we're delighted to hear what you have to say.

Mr. YANCIK. What I'd like to do is depart a little bit from my prepared statement.

Senator WARNER. Your full statement will be a part of the record.

Mr. YANCIK. Fine. And I will perhaps add a few comments here as the result of some of the things I did here today, at this hearing.

Senator WARNER. Good.

Mr. YANCIK. I will, though, limit my remarks to the coal export promotion activities, coming from the Office of Assistant Secretary for Trade Development, as they relate to the subject of this hearing coupling coal sales with the coal use technologies. I might add that in listening to both Mr. Anderson and Mr. Hardy, we very much would like to team up with them to find a way for the U.S. coal suppliers to utilize the financial resources of the two institutions in order to export U.S. coal.

We have a bias, at the Department of Commerce, and particularly in the Office of Coal Exploration. We would like to see U.S. coal used and we would not like to see some of the more marginal domestic resources of some of the countries that have been mentioned here today developed with U.S. money. That may be a very biased view but there are circumstances where we think that both institutions could develop programs that would help U.S. coal suppliers.

Before I go into describing some of the activities that we have underway, I might just take a moment and cover the current international coal trade situation. I think it illustrates the importance of developing ways to couple our coal sales with coal use technology because it will improve our competitiveness.

The United States, as you know, has been a long and reliable and leading coal exporter for over 30 years. In 1982 we exported 105 million tons, which was about 35 percent of the total international trade. Benefiting from the oil embargoes, oil price increases, and coal supply shortages, U.S. coal suppliers and their exports reached all time highs in both 1980 and 1981. However, in mid-1982 the effects of the worldwide economic recession and very aggressive competition from South Africa, Poland and from Australia was beginning to have its effect.

Prices began to come down rather precipitously on the basis that these major that these major exporters were attempting to hold their market share. U.S. coal exporters, on the basis of price alone, cannot really compete with those countries. South Africa is a low-cost producer in Europe. And Australia has that position in the Pacific rim countries. The results of that, in the first 6 months of 1983, were painfully obvious to some of the people that were in the room earlier for exporting coal. In the first 6 months of 1983 our exports overseas fell from 20 to 25 million tons which is a 45-percent decrease from the previous 6 months in 1982.

So the question relates, what can U.S. coal suppliers do to improve their competitiveness in the international marketplace? One part of that answer that was alluded to earlier in the day and is clearly obvious is that the U.S. coal industry needs to improve its inland transport infrastructure and seaports to reduce these costs, because they are a major complement of the delivered price of coal.

Now, to accomplish major improvements, I think it will require the assistance and legislative help of Congress. Senator, I know you know thes issues very well, you've been in the forefront in the leadership of attempting to work out solutions and, as you know, the administration supports legislation that will enable us to improve our seaports so that we can get on with the business of having necessary infrastructure; namely, deep draft channels as needed to meet the market requirements.

Now, I don't believe anyone in this room would disagree that inland transport reducing these costs. Inland transport costs are very important to our ability to compete. But I believe that the subject of this hearing also offers an interesting and very viable opportunity to do that same thing. We think this should be wholeheartedly supported by the private sector. I think we have demonstrated in this country that if we exploit our technological leadership that we have an opportunity to improve our competitiveness in the international marketplace whether it be coal or other areas.

With that in mind, I would just like to take a moment to point out that within the Department of Commerce, which has the primary responsibility for implementing the national coal export policy, that we have been looking at ways of how to bring these two things together, the U.S. coal sales and technology and to develop approaches which will allow U.S. coal suppliers to package products that go beyond just the sale of coal only. We've kept in mind, as we are exploring for possible opportunities, the basic precept within the national coal export policy. That is, that the U.S. Government is not going to subsidize U.S. coal exports but that the U.S. Government and administration will take whatever steps necessary to remove what impediments exist and to support private sector initiatives, to advance this type of program.

So with that, I might just go into describing briefly some of the major activities which, I must say, are at this point exploratory in nature. Because we are attempting to define just how best can we proceed in this area. At first glance it appears very simple but when begin to look at the potential markets you find its very complex. Some of the reasons were alluded to this morning. One of the first things we've been doing over the last 6 months is having informal industry consultations both with companies that are involved representing the construction and manufacture of coal-fired combusters and environmental control systems. The purpose of these discussions are to get their ideas on what type of marketing strategies do they think would best suit the various types of markets that are going to be available, whether they be in highly industrialized countries or whether they be in less developed countries such as Brazil and the Philippines that were discussed earlier. These will continue and we solicit any help that we can get and would like very much to welcome any of you to talk to coal export staff in this area.

Another area is that with the assistance of the foreign commercial service officers who are stationed in 67 embassies, and with those that are stationed within major coal importing countries, we have developed what we call marketing profiles. We have 24 of these, either major importers accounting for about 97 percent of U.S. coal that's sold overseas. As part of this market profile, with the assistance and help of the Department of Energy and the science attachés that are in these embassies, we are developing the profiles on the environmental requirements and emission control requirements. These data bases, which will all be available early this fall and will be very useful in not only helping us to structure our program but also help those companies that are looking at these countries as potential markets.

Another area, the Coal Export Program. There are two trade missions that took place in 1982. One to Europe, which was basically foreign-buyer-oriented-type mission and then the later mission in November 1982 to the Pacific Rim countries, which was organized on a government-to-government-type mission. They essentially had the same objective but they were structured differently to deal with the different market conditions that existed in those two places. Both government and industry leaders were contacted by these two missions and I believe that we have evidence, and in fact firm evidence, that as a result of these two trade missions there have been coal sales and one thing it had demonstrated to the U.S. coal industry is its very interested in remaining and continuing to remain a long-term reliable supplier.

Based on the experience from these two missions, we believe that future missions should be organized by government to government. Furthermore, that the mission agenda should be tailored very specifically to the country which these missions will be visiting. And that they should include, in the future, technical representatives that are knowledgeable about the current and prospective uses of coal in that country.

We recently completed the preliminary planning for a mission that would employ this basic approach to the southern Mediterranean countries and our discussions with the industry people, both the suppliers and the people involved in the development and manufacture of the coal use technology, have expressed an interest. So we know if we can get this mission off the ground we know that we should have industry support behind us.

The last activity that I'd like to mention here is the one that's associated with the United States-Japan energy working group. As you know, it was formed by President Reagan and Prime Minister Nakasone when the Prime Minister visited the President shortly after the election last year; he visited this country in January 1983. They agreed that this group would be set up to explore the opportunities for expanded United States-Japan trade in coal, oil and gas to identify and overcome impediments which are restricting trade in these two areas. Now, the Trade Development's Office has the responsibility for coal while the Departments of Energy and State have the responsibility for oil and gas, respectively.

Two meetings have been held by the United States-Japan energy working group one of which is sitting on my left, Mr. Charles Schotta, who is one of the members of the U.S. delegation. So if I say something here that's not exactly right, correct me and let me know. One was held in Washington on April 6–7 and the other one was held in Tokyo in July of this year. Coming out of this was a mutual assessment or, I should say one thing coming out of these two meetings, that Japan's long-term energy security can be considerably improved by reducing its dependence on oil for power generation from its current 40 percent to approximately half of that as quickly as possible, and ideally by 1990. Japan is proceeding in this direction. Unfortunately, it is not including the construction of coal-fired powerplants as actively as we had hoped that they would. One of the reasons is that they're deferring coal-fired powerplants. They say basically for two reasons. The firs being that they are heavily committed to the nuclear program and also to their L&G program because of contracts they have signed. However, they also admitted that coal-fired powerplants represent some difficulties for them to construct because of their lack of experience in using coal and environmental and siting problems. The United States offered to assist Japan in assessing the technology base for coal-fired utility plants and we have urged the Japanese Government to accelerate its oil-to-coal conversion program. I think there's an area there for our manufacturers to assist.

I will conclude with just two comments regarding what we see as the near term for the price competitiveness of U.S. coal. It is essentially that we do not see our major competitors with rapidly increasing costs so that in the next 5 to 7 years, the United States will have difficulty competing on the basis of price alone. And it may be more like 10 years. So we really do need to examine what are their marketing strategies and what can we do in this regard.

I think the dimensions of the challenge are very clear as to what we're facing. It now costs around 200 to 400 percent more to build a coal-fired powerplant than an oil-fired unit. About 25 percent of this cost differential is for coal handling and storage and for ash collection and disposal. Another 25 percent, as we heard earlier, is for pollution control systems. And the remaining 50 percent covers the additional cost of more complex boilers needed to burn coal. The lower the rank and quality of coal, the more a boiler costs.

But we do have advanced technologies to burn coal efficiently, economically and cleanly. And we do have current technologies to do that. So these technologies could be a very very important sales tool. We see that the United States continues to market coal on a "business as usual" approach and it is very likely that we could lose our standing as a major leading coal exporter. So we do have reasons to take action.

And I think the challenge is also clear to Government, to the administration, to us at Commerce, to develop ways to implement that national coal export policy with some innovative approaches. I think we need to examine what actions we can take. Perhaps one of the cooperative industry programs that could be put into place is coupling coal sales with coal use. We think that it deserves careful study and what we hope to be able to do, is to look at that and to solicit the help of the industry, to perhaps engage in dialogue that will allow us to look at the opportunities that exist there. And we look forward to working with your subcommittee perhaps to look at some of the market incentives that might be applied in this case.

[The prepared statement of Mr. Yancik follows:]

Statement of

Joseph J. Yancik
Director, Coal Export Staff
Office of the Assistant Secretary for Trade Development
International Trade Administration
Department of Commerce

Mr. Chairman, I am pleased to represent the Department of Commerce at this hearing and participate in the exploration of opportunities for new domestic and foreign coal markets through the use of advanced coal technologies. I will limit my remarks to the current coal export promotion activities of the Office of the Assistant Secretary for Trade Development as they relate to coupling coal use technology with coal sales abroad. My remarks will not address specific market opportunities as I understand the Department of Energy will be presenting an assessment of the commercial status of coal use technologies and their general market applications.

Before I discuss our activities, most of which are exploratory in nature and intended to help us define how best to exploit coal use technologies to increase coal exports, I would like to make a few remarks on the international coal trade situation. My remarks are directed towards the potential importance of coupling coal sales with its use technology.

International Coal Market

The United States has been the leading coal exporter for over 30 years. In 1982 we exported 105 million tons, which was about 35 percent of the total world coal trade. Benefitting from oil embargoes, oil price increases, and coal supply shortages, U.S. coal exports reached all time highs in 1980 and 1981. In mid 1982, however, U.S. exports began a sharp downward trend reflecting the worldwide economic recession and aggressive competition from Australia, Poland and South Africa.

Our major competitors began reducing prices to maintain their exports in the face of rapidly increasing world coal production that was far in excess of demand. U.S. coal exporters, unable for the most part to compete on the basis of price alone, began losing market share in the European market (where South Africa is the low cost supplier) and in the Pacific Rim (where Australia has that role). The results are painfully obvious. U.S. overseas coal exports in the first six months of 1983 fell to 25 million tons, a 45 percent decrease from the tonnage shipped in the same period last year.

Competition in World Coal Trade

What are the immediate prospects for U.S. coal exports and what avenues and actions are available to the U.S. coal industry to meet stiff worldwide competition? The first part of this question is not too difficult to answer. The National Coal Association's latest projection for 1983 coal export sales is 74 million tons, well below the 97 million tons forecast at the beginning of the year. Assuming no major supply interruptions, the Association foresees only minimal growth in U.S. coal exports through 1985.

That brings me to the second part of my question--what can U.S. coal exporters do to improve their competitiveness? One part of the answer is that the U.S. coal industry needs to improve the inland transportation infrastructure and sea ports to reduce transportation costs. To accomplish major improvements, the coal industry needs legislative help from the Congress and support from the Administration. Mr Chairman, you and your Subcommittee know these issues well, and under your leadership, solutions to these transportation problems are being developed.

No one disagrees that transportation cost reductions are central to our ability to compete in world coal markets, but other equally important objectives must also be pursued.

This Subcommittee's efforts to stimulate the development of programs linking coal use technologies with coal exports should be wholeheartedly supported by the private sector. We must exploit our technological strengths, particularly our technical leadership, in direct combustion of coal and associated environmental control systems. Nor should we neglect our technical capabilities to convert coal to alternative forms of fuel--oil, gas, and slurry fuels.

Coal Export Promotion Program

The Department of Commerce has the responsibility to implement the National Coal Export Policy. We have initiated a number of activities to develop programs linking coal use technologies with exports. These are preliminary efforts designed to identify the market potential for "packaged" sales. Our approach is to build on the foundation laid down by President Reagan's reaffirmation of this nation's commitment to remain a long-term and reliable coal supplier. The fundamental precept embodied in the Coal Export Policy is not to provide subsidies to coal exports, but to give active U.S. Government support to programs that will strengthen the competitiveness of the U.S. coal industry in the world market.

We have underway a number of projects which I will briefly describe. In each case, our objective is to devise model marketing programs which relate coal use technologies to export sales.

Industry Consultations: We have held informal sessions with industry associations representing coal-fired combustion and environmental control system manufacturers and individual firms to solicit suggestions for export promotion programs. These discussions have been very useful. Our efforts are focused on devising market strategies which could be assisted by or which require Government support. We welcome industry participation in this dialogue and hope that this hearing will generate more industry interest and contacts with the Coal Export Staff.

Coal Export Markets and Environmental Requirements: The Coal Export Staff, with the assistance of the Foreign Commercial Service officers stationed in the major coal importing countries, has prepared coal marketing profiles for 24 importing countries. These profiles, still in draft form, are scheduled to be released early this Fall. They are intended to be useful references for coal suppliers new to the export market as well as for established exporters. As an addendum to these market profiles, we are preparing profiles of environmental standards and emissions control requirements. These profiles are being prepared with assistance from the Department of Energy and the Science Attaches stationed in U.S. embassies. These environmental data bases should not only assist coal exporters in developing specific marketing plans, but also help in structuring appropriate Government-Industry coal export promotion programs.

Trade Missions: The Coal Export Program in the Department planned and organized two trade missions in 1982. The first mission was to Europe, and was oriented toward foreign buyers. Mission members consisted of American coal producers, industry representatives, and Government and Congressional officials who met with potential customers and energy officials in Madrid, Rome, Milan, Paris, and Brussels. The second mission was to the Pacific Rim, and structured as a Government-to-Government effort. U.S. coal, transportation, port and related industry association representatives were accompanied by Government and Congressional officials. They met with top energy decision-makers in Seoul, Korea; Hong Kong; and Tokyo and Osaka, Japan. These two missions contacted over one thousand Government and industry leaders.

Based on the experience gained from the 1982 missions, we believe that future missions should be organized as Government-to-Government efforts to realize maximium benefits for the U.S. coal industry.

Mission agendas should be tailored to the specific countries visited and should include coal use technical representatives knowledgeable about current and prospective market needs.

The Coal Export Staff has recently completed preliminary planning for a mission to the Southern Mediterranean countries. This mission would include technical representatives experienced in the use of coal. Initial discussions with industry officials indicated there is support for this approach and an interest in participating.

U.S.-Japan Energy Working Group: The U.S.-Japan Energy Working Group was formed by Prime Minister Nakasone and President Reagan in January 1983. The Group's purpose is to explore opportunities for expanded U.S.-Japan trade in coal, oil and gas and to overcome constraints to such trade at both private and government levels. Trade Development's Coal Export Staff has the lead responsibility for coal while the Departments of Energy and State have the lead for oil and gas, respectively.

Two meetings of the U.S.-Japan Energy Working Group have been held to date--April 6-7, 1983 in Washington and July 4-5, 1983 in Tokyo. There was agreement that Japan's long-term energy security required reducing its current 40 percent dependence on oil-fired electric power generation to less than 20 percent by using alternative fuels, including coal. However, Japan is proceeding very slowly in building coal-fired plants citing lack of experience in coal burning, environmental, and siting problems. The United States offered to assist Japan in assessing the technology base for coal-fired utility plants and urged the Japanese Government to accelerate its oil-to-coal conversion program.

Concluding Remarks

Economic conditions in most industrial countries are beginning to improve and demand for coal is expected to show some increase. However, the outlook for the price competitiveness of U.S. coal in overseas markets is not expected to change much through the rest of this decade. Clearly, U.S. coal exporters need to take a hard look at their marketing strategies. All elements of the coal exporting and coal use chain should be examined for innovative ideas to improve the market potential and competitiveness of U.S. coal in the international market place.

The dimensions of the challenge are clear. It now costs around 200 percent to 400 percent more to build a coal-fired power plant than an oil-fired unit. Around 25 percent of this cost differential is for coal handling and storage and for ash collection and disposal. Another 25 percent is for pollution control systems. The remaining 50 percent covers the larger and more complex boilers needed to burn coal efficiently. The lower the rank and quality of coal, the more costly are the boilers.

Advanced technologies to burn coal efficiently, economically and cleanly have been developed in the United States over the last 10 years. These technologies could be an important sales tool for our coal exporters. If U.S. coal exporters continue to market coal on the old "business as usual" approach, it is very likely that we will soon relinquish our leading coal exporter role and become a marginal supplier.

The challenge to develop innovative ways to implement the National Coal Export Policy is also clear. When Secretary Baldrige announced the Administration's policy in July 1981, U.S. coal exports were at an all time high. Coal suppliers took advantage of the surge in demand and the supply shortage. However, market conditions have changed dramatically and they are now quite unfavorable to U.S. coal sales. More than ever, we need to initiate cooperative Industry-Government programs consistent with the basic philosophy of the National Coal Export Policy.

One such cooperative program could be based on coupling coal sales with coal use technologies. We believe this concept deserves careful study to produce successful marketing strategies. The Coal Export Staff will continue its efforts in this area and we welcome industry's input to identify market opportunities. We also look forward to working with this Subcommittee to develop incentives which encourage oil dependent nations to purchase U.S. coal use technology and U.S. coal.

Senator **Warner**. Thank you, Mr. Yancik.

STATEMENT OF CHARLES SCHOTTA, DEPUTY ASSISTANT SECRETARY FOR ARABIAN PENINSULA AFFAIRS, DEPARTMENT OF THE TREASURY

Mr. **Schotta**. Thank you very much, Senator Warner. The Department of the Treasury is grateful to you for giving us this opportunity to come and give our views on coal technology and I am personally pleased to represent the Treasury here. I would like, with your permission, to give a summarization of my prepared text and ask that it be included in the record as submitted.

Senator **Warner**. Fine.

Mr. **Schotta**. Thank you very much. In general, the Department of the Treasury shares the views expressed by the other members of this panel with respect to the desirability of utilizing whatever governmental resources that we have available consist in the financing of conditions in other parts of the world which will be conducive to increased coal use and hopefully increase exports of U.S. produced coal.

I'd like to make a couple of points, more general points than that. We, at Treasury, believe that one of the most useful contributions that can be made to increase demand for coal in general will be restoration of high and economic stable growth worldwide particularly in those developing countries which, in the future, can and must serve as some of the power increase to the market share. Second, we believe that restoration of sound economic growth will bring with it benefits of lower interest rates which will surely, given the tremendous capital costs of both coal-use technology and coal transportation equipment with resulting cost effectiveness. The administration proposals to achieve that end which are before the Congress now certainly are worthy of support. We are grateful that the Congress has so recently passed the U.S. proposal to fund the early increase to the International Monetary Fund because we believe that will in countries like Brazil which are, as we've just heard, potential coal markets for the United States. The quota increase will allow us to improve the stability of the international financial system and create an atmosphere conducive to economic growth.

The availability of external capital resources is likely to have a very strong influence on coal's future and the future use of coal in the developing nations. I would like to direct many of my comments to the developing world since those are the areas which have grown quite rapidly and which are in transition from rather rudimentary energy systems to more advanced energy systems and the opportunities are there to capture a share of this growing market. Many of these countries have not adjusted their economies to the higher energy costs that the oil price has forced on them. This process is going to take time and will be greatly facilitated by the provision of external assistance that our multilateral development banks such as the World Bank are able to provide.

We believe very strongly at the Treasury, as a matter of U.S. Government policy, that any projects funded by the World Bank or the regional development banks in a area should meet the test of economic viability. Nevertheless, we have a strong policy desire for those countries to see them develop their energy systems in a way we can minimize this. The undue and excessive reliance on imported oil which they share, regrettably, with us and the industrialized countries. So we have laid great stress on the Energy Program of the World Bank which occupies approximately 25 percent of its total resource use at the present time. We have laid great stress on directing this program to build or to assist these developing nations in building a coal-based, coal-fired electric generating facility; what it would cost in contrast to oil which we think is not as desirable. The World Bank has engaged in considerable technical assistance to countries to encouage electrical energy programs. The World Bank takes an enormous portion of its energy loan support powerplant development and at least many of those powerplants that are built are going to be coal-fired. The World Bank also utilizes a very appropriate portion of its loans and its technical assistance to assist some of the develping countries in utilizing their own indigenous coal resources. Experience has shown that many of these countries cannot possibly satisfy their own internal demands for coal as they become part of the coal using system and develop coal using facilities even though they produce some of their own coal. They need to have good markets for the supply on this incremental coal.

I'd like to call attention to one other facet of work among the multilateral development banks where I'd like to focus, Senator, my remarks here. In addition to actually providing a portion of the finance for the construction of powerplants and things of that nature, the World Bank in combination with the U.N. Development Program performs overall energy sector, including evergy R&D surveys, of the developing country and stimulates the introduction in that way of new and advanced technology for the utilization of all fuels including, very importantly, coal.

Senator, I think the thrust of my remarks is and my particular purpose at this hearing was to call attention to the contribution that the multilateral banks, in particular, can make and are making to an expansion of coal use in the developing world and to encourage the move away from oil. Do you have any questions? Or, if any members of the panel or audience have questions, I will be glad to answer them.

[The prepared statement of Mr. Schotta follows:]

TREASURY NEWS
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Statement
by
Charles Schotta
Deputy Assistant Secretary
for
Arabian Peninsula Affairs
Before the
Senate Committee on Energy and Natural Resources
Subcommittee on Energy and Mineral Resources
Field Hearing at
Virginia Polytechnic Institute and State University
Blacksburg, Virginia

August 9, 1983

Thank you for your invitation to speak before the citizens of this region of Virginia who have such a strong interest in the U.S. coal industry. I welcome this opportunity to talk about the potential of enhanced technologies for development of new coal markets.

At the beginning of this century, coal was the dominant energy source and feed stock used by industrialized nations. However, the discovery of large reserves followed by supporting technological advances made oil and gas significantly cheaper and more convenient to produce, transport, store, and use than coal for many uses. Accordingly, coal's contribution toward the world's energy requirements eroded. By 1973, coal provided less than 30 percent of the world's primary energy requirements.

Since 1973, the long-term declining trend in coal's share of free world primary energy markets has eased if not reversed and output has grown. It is now significantly less expensive to generate heat from coal at large stationary facilities than from oil. This change has primarily been attributable to the very substantial appreciation of the price of oil relative to alternative fuels. Together with deep-seated concerns about the reliability of external oil supplies, the relative price changes of the past decade have promoted a renewed and growing international appreciation of coal's potential role in fueling industrialized economies. These circumstances bestow upon the United States, with its vast recoverable reserves and under-utilized coal mining capacity, the potential to become a leading exporter of steam as well as metallurgical coal.

Substantial realization of the potential for increasing coal use, particularly that of U.S. coal, is heavily dependent on private sector investment in enhanced coal use and coal transportation technologies, as well as other considerations such as oil prices. Many of the easy conversions from oil to coal-based technology have been made, particularly in industrialized countries. With recent world recession, and uncertainties about the price of oil, the general economic climate has not been conducive to substantial further investments in capital-intensive fuel conversion projects. Existing facilities are frequently not fully utilized due to soft demand for end-products. Consequently, significant growth in coal demand is dependent on economic growth and to some extent may require penetration of new markets and less reliance on demand from large stationary plants.

Long-term forecasts generally suggest some increase in energy demand due to a resumption of economic growth. Many project economic growth for the remainder of the century averaging 2.5-3.0 percent for the OECD area as a whole, with somewhat higher growth rates for other free world areas.

While economic growth may promote increasing coal demand, that demand could be supplied from an increasing number of sources. The U.S. producer share of foreign coal markets could be influenced by strong competition from foreign supply sources. Coal resources have been identified in more than 100 countries, although most production is presently concentrated in a few developed countries and centrally planned economies.

However, coal is not a homogeneous substance. The particular characteristics of coal deposits vary due to a multitude of factors affecting the coal over the geologic time required for its formation. Few nations offer the breadth of coal varieties found in the United States. The wide diversity of our coal deposits broadens the range of potential end-use customers for U.S. producers relative to their major competitors. This diversity in coal deposit characteristics also broadens the range of technologies which may be applicable to development of future markets.

Coal use technologies are themselves not homogenous. They offer different approaches to similar problems, use different levels of scientific sophistication, require varying time horizons for implementation, and face different impediments to ultimate deployment. All of them, however, require at least some capital investment to implement, and many require further research and development expenditures by private firms.

Widespread commercial implementation of new coal technologies is most likely to occur under circumstances which offer investors reasonable prospects of a competitive rate of return and recovery of their capital. Technological innovation will be needed to increase the breadth and depth of coal markets, which in turn will require time and a healthy economic climate.

Some U.S. Government policies already in place should contribute progressively to that process through the course of the economic recovery now under way. One measure directly benefiting coal end-users who invest in new equipment is the Accelerated Cost Recovery System (ACRS) of tax depreciation enacted by the Congress in the Economic Recovery Tax Act of 1981. A second feature of that legislation, the 25% incremental research and development expenditure tax credit, could also encourage improvements in coal technologies. Coal liquefaction and gasification research contracts and demonstration projects financially supported by the Department of Energy and the Synthetic Fuels Corporation may also be helpful.

Continuing efforts of this Administration to remove unnecessary regulations are also likely to facilitate increasing coal use through improved efficiency of the transportation sector. The recent decision of the Interstate Commerce Commission to deregulate rail transportation rates for coal will open the door for domestic producers to vigorously negotiate for lower rail transit fees and force the U.S. rail industry to recognize the intense international competition for world coal trade. As transportation costs for U.S. coal exports are significantly higher than those for supplies from other major sources, the rail industry will be under significant pressure to improve efficiency and reduce costs. Otherwise, the industry may realize continuing erosion of coal traffic volume due to displacement of U.S. coal exports by foreign supplies. The force of this international coal market competitive pressure could be augmented by further development of alternative domestic transportation modes such as coal slurry pipelines.

Passage of port improvement legislation with appropriate user fee provisions may further improve the prospects for expansion of foreign markets for U.S. coal. The Administration continues to support legislation in this area. Without a sound basis for financing port improvements, the projects will simply not be undertaken.

Certain financial proposals that the Administration has advanced for legislative consideration could also facilitate advancement of enhanced coal technologies.

For example, Congressional action to reduce the rate of growth in government expenditures would tend to reduce the cost of capital to private borrowers. When capital costs for coal-fired facilities are often 1.5 to 3.0 times those for oil or gas installations, high interest rates can discourage conversion to coal. Similarly, passage of Administration proposals to fund the U.S. share of increases in International Monetary Fund (IMF) quotas and other resources and contributions to Multilateral Development Banks (MDBs) are needed to reinforce confidence in the basic international financial system, to provide for continuing availability of capital to poorer nations for industrialization purposes, and to re-establish an environment conducive to soundly based economic growth.

The availability of external capital resources is likely to have a strong influence on coal's future role in the developing countries. Many have still not fully adjusted their economies to the sharply higher energy costs thrust upon them during the past decade. This adjustment process will continue for some time and would be greatly facilitated by the provision of the IMF and MDBs with additional resources as proposed by the Admininstration. Availability of external capital to LDCs from these institutions may well facilitate their acquisition of enhanced coal use technologies.

Financing is provided by the IMF only as a means to achieve its ongoing systemic responsibility of promoting a cooperative and stable monetary framework for the world economy. This role is vital in restoring world trade growth and creating economic conditions favorable to sustained demand for exports such as coal.

All countries eligible to draw on IMF financial resources must have a balance of payments need. Loans are made available in phases or tranches as the borrowers implement agreed economic policies commensurate with the cause and magnitude of financial need. The conditionality attached to IMF lending is designed to assure that the country undertakes short- and, if necessary, medium-term structural adjustments that will correct fundamental international payments problems and restore the borrower to a sound financial footing.

Adherence by the borrowing countries to IMF negotiated economic programs is usually viewed by financial market participants as mandatory to qualify the borrower for other new private and official financing. Thus, for countries faced with significant external imbalances, IMF resources are critical to mobilization of the trade and technology transfers needed to effect adjustment in an orderly manner. Orderly adjustment entails continued international trading accompanied by redirection of internal economic activity toward improved economic efficiency and greater responsiveness to world market realities such as significant realignment of, and sharply higher, real energy prices.

The MDBs augment the IMF by promoting development of a more secure and stable world through steady economic growth. The banks attempt to strengthen the ability of LDCs to participate more fully in a free, open, and stable international economic system by acting as catalysts for economic activity. Their activities encourage rational LDC economic policies which contribute to global economic efficiency and enhance prospects for further growth.

Energy consumption in developing countries, which includes the centrally planned economies of China, Cuba, Kampuchea, Mongolia, Viet Nam, and Yugoslavia, is projected by the World Bank to grow at an average 4.5 percent per year through 1995 based on GDP growth averaging 4.8 percent. Coal consumption growth of 4.4 percent is forecast for these countries while coal production growth of 3.9 percent a year is expected. By 1995 the bank projects that 15-20 LDCs will be net coal importers of nearly 80 million tons of coal per year. In 1980, developing countries imported only about 11 million tons. These projections, which foresee the share of coal use in LDC electricity generation rising from 30% to 38%, do not require conversion of existing oil-fired units to coal, which is relatively expensive.

However, government action may be necessary to facilitate coal imports. Public financing of infrastructure for coal handling and transport will probably be necessary in many instances before potential users (power plants, cement factories) will undertake the necessary industrial investments and embark on contractual arrangements with foreign suppliers. Nevertheless, few developing countries are studying the coal import option or undertaking the necessary infrastructuure investments. The urge to develop their own indigenous energy resources is strong. The Bank, which is the single most important official source of external capital for energy development in LDCs, is also prepared to finance studies to identify prospects for increased use of coal, particularly, in the power, industrial, and household sectors.

The World Bank and the UNDP (United Nations Development Programme) are jointly playing a key role in assisting over sixty LDCs to formulate sound energy sector policies via the joint Energy Sector Assessments program. In response to specific requests from governments, teams of World Bank and UN personnel and consultants assess the major problems faced by individual countries and evaluate options for solving those problems. Assessments completed to date have been of very high quality. These studies have generally recommended realistic energy sector pricing policies, scope for foreign and local private investment, and reliance upon both imported and domestic coal when appropriate.

The Administration believes that MDB lending in general should be consistent with an economically rational, overall development strategy which is responsive to market forces. MDB lending for coal development should meet the same criteria as MDB lending for other sectors. In particular, the MDBs should support only those coal projects which are economically, financially, and developmentally sound, as well as compatible with the interests of American producers and consumers. Additionally, MDB coal lending should catalyze rather than displace such other potential sources of finance as local and foreign private investment, international commerical bank lending, suppliers' credits, official export credits, and bilateral foreign aid. MDB lending must also be linked to policy conditionality sufficient to ensure sound energy sector policies.

While managerial and capital resources are not in so short supply in industrialized countries as to promote efforts comparable to the World Bank/UNDP Energy Assessments Program, Economic Summit countries and other members of the International Energy Agency (IEA) have taken joint steps to support increasing coal use. In June, 1980, Heads of State at the Venice Economic Summit supported a goal of doubling coal use by the early 1990's to "break the link between economic growth and consumption of oil." Subsequently, IEA Energy Ministers have consistently reaffirmed their governments' commitments to expand the use, production, and trade of coal on an economic basis and with effective standards of environmental protection. To supplement these political statements, the IEA has established a Coal Industry Advisory Board to assist governments in formulating appropriate policies and identify areas of significant potential for particular attention of industry and other energy users.

In summary, a host of governmental and private sector initiatives promoting enhanced coal-based technologies and increasing coal use have evolved over the past few years. Commensurate with the nature of the resource itself, the initiatives underway are diverse. They are worldwide in scope, employ both short- and long-term perspectives, and utilize strengths of both the government and private sectors. While additional measures specifically oriented toward coal utilization may be judged worthwhile at some point in the future, existing arrangements appear sufficiently flexible and dynamic to fulfill identified needs. Constant attention to the health of major world economies is clearly needed however. Affirmative Congressional action on the economically-oriented proposals of this Administration which I have mentioned would be helpful in this regard.

Senator **Warner**. I do hope that you've had the opportunity to comingle with others and there has been some discussion other than the hearing today, and I am very grateful to you, of course.

And now, we will have Mr. Eugene Lubarsky.

STATEMENT OF EUGENE LUBARSKY, VICE PRESIDENT, BUSINESS DEVELOPMENT, KELLER CORP.

Mr. **Lubarsky**. Thank you Senator. First of all, I'd like to thank Mr. Sindelar for inviting me to speak and placing me where I was on the agenda so that all the other speakers could set the stage for what I have to say. I'm here to present the enhanced coal technology we all are looking for today. Before I get into that, though, I'd like just to touch base on the numbers that were said before just to remind everybody what we're talking about is coal exports. The forecast for 1983 was 80 to 85 million tons. It doesn't look like we're going to hit that yet, but we're talking, you said, 20 million in 6 months. Of course, we hope that demand will bounce back when the econmy turns around.

We have to remember that the rest of the world is looking for coal exports, too, to help their economies. Poland, Australia, Canada, and South Africa. Poland is trying to start exporting 38 million tons a year. They need that for their economy, they are in really bad shape. We think Australia, South Africa, and Canada are going to do the same thing. Now, there were a couple of countries that weren't heard from today, or at least weren't mentioned. I think they're important. China is now getting into an export position and, with the help of an American company, they're going to open the largest open cut mine in the world which has a reserve of 1.4 billion tons and, if its on schedule, its expected to produce 15 tons annually in 1985 with about half of that volume going to Japan, South Korea, and the Philippines. And you can bet the price will be set at what it has to be to go. Russia is the other area where nothing has been mentioned but we have evidence that there is considerable effort on their exporting more coal. They have been talking very recently, its been in the press, with a German company to buy surface mining and coal processing to convert a low grade lignite in the Krasnoyarsk area of Siberia to synthetic liquid fuels for shipment to industrial centers about 4,000 miles away. Russia reportedly has 9 billion tons of lignite and supposedly has 80 billion tons of hard coal. Russia has also been talking about building a slurry pipeline. In fact last year, we were approached by an Italian company to help them sell steel for a 3,000 mile pipeline that was going to be built from Siberia to Odessa. Odessa is on the Black Sea and obviously would be for export. We spoke to the State Department at that time, the Commerce Department, and they said—this was about the time of the Soviet gas pipeline—they said no way would you be able to export any technologies. So we told them to forget it. A few months later, in the press, it was announced that a couple of American companies had announced that they were going to build a pipeline to export coal via a slurry from Russia. Now, the forecast would be about 60 million tons of coal exported per year if a pipeline like that is being built. Its a fantastic project that will cost $40 to $50 billion. If it ever goes, it will again, affect world prices.

Again, we should realize that energy, anything that can be burned in a boiler, can substitute for coal. The Soviet pipeline has just been announced as being completed. That's 2,780 miles. The pumping stations aren't in yet, but they are forecasting at capacity to pump about 40 billion cubic meters of gas a year. That's equivalent to about 54 million tons of coal, approximately 228 million barrels of fuel oil on a Btu bases. Of course, what this means is that competition for the coal market will increase and even though we are getting more competitive at delivering coal through our ports, I think the best way to increase coal exports would be to expand our market.

Before I get into exporting, I'd like to mention what methacoal is. I'm sure most of you have never heard of it, even though we've been trying to sell the licensing technology for many years, we haven't been very successful because it hasn't looked too attractive in the past. First of all, methacoal is not really a slurry, a pulverized coal mixed with methanol or methanol and water. Actually, pumping pulversized coal in an alcohol slurry would not be advisable because coal has an unusually high settling rate in alcohol. One of the secrets of methacoal is to optimally adjust the ratio of solids to liquids and, by virtue of natural chemistry involved, a stable, lubricating coating occurs on every carbon surface. We believe this is why methacoal, in about a two-thirds coal to one-third alcohol ratio, flows as easily as oil. When properly blended, methacoal is a stable suspension of pulverized coal or lignite solids in low molecular weight alcohol, preferably methanol, by virtue of superior stabilify, mineralogical and combustion characteristics such suspension exhibit potential advantages over alternate coal-based fuels such as coal oil and coal-water mixtures.

I can't delve into all the technical points today but I'm going to try to highlight some of the areas where we think that this can enhance exporting. In increasing the coal export market, the best way is to convert oil-fired boilers to burn a coal-based fuel. Converting to burn coal directly is very expensive and also results in loss of boiler capacity. As oil prices have stabilized temporarily, the longer indicated pay out time required precludes utilities from making this investment, especially on older boilers with short use rate remaining, even if the capital could be raised. Methacoal can be burned in existing oil-fired boilers with only modest conversion cost for new burners and controls with a minimum derating, or loss of boiler output. A limited data has been obtained in 100 and 700 horsepower boiler tests in Department of Energy test burns program conducted at the Pittsburgh Energy Test Facility over the past 2 years. The final results on the 700 burn program hasn't been published yet but we understand it was very successful. However, this data is not sufficient to demonstrate the effect of deposit buildup on a long-term basis. No one is going to make an investment without some proof of this performance.

The second way, of course, to increase competitiveness of U.S. coal in world markets is to decrease delivered cost. It has been observed that transportation and handling costs for exporting coal can be greater than the mine mouth cost of the product itself. The ability of methacoal to reduce transportation costs and improve delivered quality at the same time, are reasons why we believe that methacoal is very cost competitive. Methacoal reduces transportation costs in several ways. By pulverizing coal at the mine site in the presence of methanol, moisture sulfur compounds present as pyrites, some ash can be eliminated. This means that instead of paying for moving noncombustibles, we pay for transporting more Btu's. This carries through for the whole transportation system for handling costs at export and import ports as to the delivery costs. As a side benefit but a very important one, by extracting moisture from the coal at the mine methacoal can be produced in arid areas, usually with no local water required. In areas where high moisture coal is prevalent, excess water above processing needs can be returned to local use for irrigation and for use in land reclamation. And we think this is very important. Also, the need for expensive water washing and the loss of by-coal particles which occur and are being sent back in the waste line with the washing water, would be eliminated. Conservative estimates indicate that 20 to 30 percent of coal now being mined is lost and ejected to the spoils where they impose a further energy penalty in their disposal. Methacoal creates an immediate 15 to 25 percent increase in Btu production from existing mining operations without adding expenditures in capital for energy and this would result in a lower impact of the local environment which in current operations has the potential problem of polluting the local water bed. Methacoal can be burned, also, in coal-fired boilers. We don't know yet what the economics is but we think that it may be able to show an economic payout because, in moving coal in a slurry in the suspension form, when it gets to the coal boiler it can be evaporated out. The dry coal can be used in the coal boiler in a similar way to the way it is being used today. What has happened in the interim is the sulfur has been removed and perhaps an ash so we are really reducing the sulfur that might normally have been used if the coal hadn't been delivered in that way. That probably has a positive effect on helping the acid rain problem. No testing has been done but we suspect that it can't be worse, it's going to get better. In addition, if that procedure were to be followed at the boiler the liquid fuel that is extracted, which we call methafuel, can be used in connection with a turbine generator. A turbine generator can be put in front of that coal-fired burner and you can use methafuel, which has already been tested by a major turbine generator supplier and is considered safe. Now, an example of the effect it would have is in a 25-megawatt turbine in front of a 100-megawatt coal-fired boiler would increase thermal efficiency in a coal operation from roughly 32 to 40 percent. It's very significant. Cost of this increased generating capacity for a turbine is about $400 per installed kilowatt compared to numbers we heard today of over $1,000 for coal-fired boilers and somewhat under $1,000 for new oil-fired burners. Thus the use of methacoal would reduce sulfur emissions plus produce fuel savings and deferral of capital investment for new generating capacity.

OK, why hasn't it been adapted? Well, Cantel (sic) Corp. is a small R&D company and, from what I see, they tried to sell the patent technology. So far they have spent probably one million dollars on R&D work by both the Cantel (sic) Corp. and the other industry and the Government research organizations. A very important point is that this does not include money that's been spent by the Japanese Government. About 3 years ago a project was started over there by Mitzubi (sic) and was paid for by Mitty (sic) and, we just spoke to them 3 weeks ago, and they're still continuing the project for another year.

We have entered into an agreement with Alaska Interior Resources, Inc. to construct a million ton per year methacoal plant after a 5,000 ton per hour methacoal plant comes on stream in 1990. The gas to produce methanol will come from the North Slope and the coal will be there in the middle of the field. We are working on a shorter term project to convert a 25 megawatt plant up there on location which is currently burning coal. Its very difficult pricing the world on coal and oil to economically justify that kind of a project on a distributive economic basis but we are hoping that will be the first project we can get into of a commercial size. We are also discussing an $18 million dollar demonstration project with a Midwest utility converting 50 megawatt oil-fired plant to burn methacoal. After the demonstration is successful the project will be expanded into a commercial venture of the size, probably, which can supply 800 megawatt capacity. The methacoal plant that will be built initially could be converted to a methanol plant, and the methanol plant could operate on the waste heating of the methanol plant that will be built during this period. This is a very interesting concept because that methanol plant will provide a market for substantial amounts of distressed or surplus grains in the area.

I'd like to leave you with these thoughts. Coal is our most abundant resource. Methacoal makes available the cleanest, most efficient way to mine, process, transport, and burn that coal with a minimum capital conversion cost and with the maximum efficiency in existing boilers, regardless of temperature. An 11-percent mixture of methanol and coal and the rest water will not freeze at −40° F. What's needed to permit this development to be utilized by industry and utilities here and abroad is a meaningful demonstration as soon as possible to provide the confidence to convert existing plants to the use of methacoal. A tax incentives have been considered and to date have not seemed to help the methacoal demonstration. Apparently better tax shelters with less risk were available. Reduce cost of oil and gas has reduced the likelihood of making capital investments for alternate fuels which payout in a short-time line. If Congress eliminates tax benefits inherent in leased back arrangements, as is currently being discussed, but permits those projects which provide alternate fuels to continue to receive these benefits perhaps some progress could be made in attracting energy capital. Also, perhaps permitting the interest paid on industrial bonds to be tax free when invested in alternate fuel projects might help attract investment capital. Other areas of tax incentives are probably best left to those who have more expertise in this area.

Although much effort is being spent developing coal-water slurries because of its expected lowest cost on a Btu basis, methacoal has been shown to provide better performance on carbon conversion and boiler efficiency. Just for the record, if you use the price of methanol at 70 cents, which computes to $10.90 per million Btu, and if you use coal that is $1.20 per million Btu, the increase in cost attributed to the methanol at about a ratio of 12 percent methanol, 20 percent water, 68 percent coal and it comes out to $2.50 per million Btu. It's not that much more and it's a lot lower then oil at $28 a barrel or $4.50. But even so, that doesn't tell the story because that's only telling you what it costs you per Btu. The question should really be, what is it costing you to generate electricity? There is a saving in transportation, a saving in handling, and you're getting a better product with more Btu's, maybe you're better off, even thought the calculation says its more expensive.

Certainly it shows to be marginally more expensive than coal-water. I really believe that the methacoal technology meets the goals of this hearing, as described by our chairman. Methacoal can increase domestic coal consumption on an environmentally sound and acceptable basis. Using more coal would make the United States more energy independent, improve our balance of payments, and aid our domestic economy by putting more miners to work and provide the means to construct more capital projects, with the attendant work force requirements they would entail. Where less developed nations have a coal resource they can be developed. The methacoal technology would permit the rapid development of this resource using existing infrastructure developed for the use of oil which, in most cases, has had to be imported at the cost of balance-of-payment deficits and a loss of employment in that country. Brazil comes quickly to mind. The need to develop new technology to enhance our ability to market coal has vital implications to the economy of the United States and the world. Although there is apparently a temporary oil surplus, the oil resources which abound in the Middle East continue to be in great peril. Iran has threatened to stop shipment of oil through the Strait of Hormuz if Iraq endangers Iran's oil capability in any way. The United States has warned that military force will be used if necessary to maintain the free flow of shipping in the Persian Gulf. The unstable situation in Central America certainly suggests that no oil source in South America is secure even though the civil unrest in Central America has not yet spread to South America. We are living in a world of turmoil with many areas currently engaged in open hostilities around the world. U.S. energy independence may be a key to achieving world stability. We in the energy field can show the world that coal can take the pressure off oil for long term, our statesmen may then get the time needed to work toward achieving the world peace we all desire. Thank you very much.

[The prepared statement of Mr. Lubarsky follows:]

METHACOAL *America's Safe, Affordable Alternative to Oil*

METHACOAL CORPORATION
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Testimony presented to the U.S. Senate Subcommittee on Energy
and Mineral Resources Field Hearing
August 9, 1983

My name is Gene Lubarsky. I am appearing here in the capacity of Vice President of Business Development for the Keller Corp. and as a consultant to the Methacoal Corp. which is a subsidiary of the Keller Corp. and holds the exclusive patent rights to the Methacoal Technologies on a worldwide basis. With me today is Mr. Frank Keller, Chairman of the Methacoal Corp.

We appreciate the opportunity to offer our comments and observations at this Senate Subcommittee Field Hearing which has been called by Senator Warner to focus attention on enhancing coal technology for increasing coal's market for the 80s and beyond. We would like to concentrate on the impact of enhanced technology on exports but much of what we will offer can also be applied to our domestic coal markets as well.

Before we discuss how we believe the Methacoal Technologies can play an important role in increasing the exports of our very abundant coal resources, perhaps we should take a look at what is being forecasted to be the total coal export market. I suppose you can get as many forecasts as forecasters making them. For the sake of this discussion, let's use a forecast which appeared recently in a Washington newspaper and was attributed to a top official of the Coal Exporter's Association. Actual coal exports for the first six months of 1983 indicate that this forecast may be somewhat optimistic, however.

It was stated that U.S. coal exports will drop more than 20% this year as worldwide coal demand in the recession-ridden steel and electric utility industries continues to stagnate. U.S. coal exports in 1983 will total 80 to 85 million tons compared to 105 million tons last year and a record 110 million tons in 1981. The hope, of course, is that demand will bounce back once the world economy turns around and the huge coal

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stockpiles held by consumers is dissipated. However, in today's economy coal exporters like Australia, Canada, Poland, South Africa and the United States are competing in a buyer's market. U.S. exports were especially hard hit in the first four months of 1983 at 21 million tons down 41% from the same period last year according to Commerce Dept. reports.

High mine to port transportation rates help make U.S. coal among the world's most expensive. Many long term contracts go to lower-cost producing nations which, with the strong U.S. dollar, has left the U.S. a spot supplier at the mercy of market booms and busts.

The Future for Coal Exports

We must look realistically at the future for coal exports from the U.S. One of the most severe problems was identified as inadequate port facilities when during the 1979 Iranian Crisis, long delays were encountered at U.S. ports by threatened consumers who were able to switch from oil to coal. Port expansions since then has alleviated long delays as well as has the reduced steel and utility demand.

Let's take a look at what is happening in some of the exporting countries. In Poland, the increase and stabilization of coal production is considered as the basic condition for overcoming Poland's current economic difficulties. Polish coal exports are now forecast to be 38 million tons annually over the next decade, down from a peak of 45 million tons in 1979 but up from 16.5 million tons in 1981 and 28.5 million tons last year, when labor and social unrest prevailed. This increase in exports is vitally needed if Poland is to have any hope of regaining acceptance by the world's financial community.

Australia and South Africa certainly count heavily on their coal exports to help balance their trade positions and Canada has been studying very intensely how they can increase exports of the coal in their western provinces to Pacific Rim Countries.

Add to these exporting countries the recently announced plans by China to open the world's largest open-cut mine in the Shanxi Province in Central China. This mine which will be developed with the aid of an American company, has reportedly 1.4 billion tons of proven coal reserves and is expected to yield 15 million tons annually. More than half this coal will be exported into markets principally in Japan, South Korea, and the Philippines. The project reportedly has experienced some delays because of a drop in the price of Chinese coal sold to Japan under a long-term contract which has fallen to $40 per ton from $52.75 according to market sources. We would venture to guess that once this mine gets into production which was originally scheduled for July 1985, the price will be set as much by political considerations and the desire for hard currency as by a profit motive and competitive market forces.

Very recently it has been reported that the Soviet Union has been looking at developing huge coal reserves in Siberia. Most recently talks have been held with a German company for the sale of strip mining and coal processing equipment to develop huge reserves in southern Siberia. Talks with the German government in the late 1970s indicated the Soviets would transform low-grade lignite in the Kransk-Achinsk region of Siberia into synthetic liquid fuels for shipment to the Soviet Union's industrial centers 4000 miles to the west. This of course would free-up Soviet oil reserves which could be sold in world markets to obtain needed hard currency to pay for imports. The Soviet Union is reported to have 9 billion tons of lignite, a low grade moist coal, in concentration in the Kansk-Achinsk region.

The state of the art of liquid synthetic fuels would make one speculate that this would be a very costly undertaking. However, late last year some American companies announced their intention of aiding the Soviets in building a coal slurry pipeline to carry upwards of 60 million tons of coal per year from Siberia to Moscow or to the Black Sea where it could be exported to Western Europe or to the Middle East. The idea to use coal slurry technology has been known to the Soviets since at least 1977 when a U.S. government expert presented a paper based on Methacoal Technology at an international energy conference on coal resources held in the U.S.S.R. in November 1977. Early last year, an Italian steel company approached the Methacoal Corp. to help them get the steel pipe business for a 3000 mile pipeline from Siberia to Odessa on the Black Sea but was thwarted when Methacoal executives refused to participate in any venture after discussions with our State and Commerce Departments. However, access to published Methacoal patents could permit the Soviets to develop the technology to their benefit. Using methanol to transport bituminous coal or lignite from Siberia as Methacoal seems to be the only logical way of developing these large reserves taking into account the very low temperatures in Siberia and the lack of a transportation infrastructure to move the coal to market.

We also should not overlook the progress of the Soviet gas pipeline which will impact on the market for other fuels. The 2780 mile pipeline is apparently now in place according to a newspaper article dated July 28th. Though the task of installing 42 pumping stations lies ahead, when the line is operational it reportedly will have a capacity of 40 billion cubic meters of gas per year or the equivalent of 54 million tons of coal per year or 228 million barrels of fuel oil per year on a BTU basis. Although a price to West Germany's Ruhrgas of $4.65 per million BTUs has been announced, contracts signed with Austria, France, West Germany, West Berlin and Switzerland and a potential commitment of 4 to 6 billion cubic meters per year with Italy will account for less than half the pipeline's capacity. Although the Soviets will doubtless try to maintain a maximum market price, the need to fill the pipeline to obtain hard currency could result in discounts if required.

What all this means of course is that there is going to be increased competition for solid coal sales from a lot of different foreign coal producers and other fuels. Most foreign producers will be in a lot better position to deliver lower cost BTUs than we, even though our ports have reduced handling and demurrage costs. The capability to load very large cargoes may help United States port competitiveness, but if interest rates should turn up again as is forecasted by many economic analysts, the advantage of lower transportation costs in large vessels would be offset by higher inventory carrying costs.

Methacoal Can Help Increase Exports

How then can we face this ever increasing competition of foreign coal. We believe we can do that by the use of Methacoal. We have referred to Methacoal often today. What is Methacoal and how do we think Methacoal can play a role in increasing U.S. coal exports? First of all, Methacoal is not merely a slurry of pulverized coal mixed with methanol or methanol and water. Actually, pumping pulverized coal in an alcohol slurry would not be adviseable since coal has an unusually high settling rate in alcohol. One of the secrets of Methacoal is to optimally adjust the ratio of solids to liquids and by virtue of natural chemistry involved, a stable lubricating coating occurs on every carbon surface. We believe this is why Methacoal in about 2/3 coal to 1/3 alcohol ratio flows as easily as oil.

When properly blended, Methacoal is a stable suspension of pulverized coal or lignite solids in low molecular weight alcohols, preferably methanol or ethanol. By virtue of superior stability, rheological and combustion characteristics, such suspensions exhibit potential advantages over alternate coal-based fluid fuels such as coal-oil and coal-water mixtures.

With the time available to us today, we will not be able to delve into a technical examination of the coal conversion process. Instead, we would like to concentrate on what the use of Methacoal Technology could mean to the United States and to the free world in general.

One of the best and easiest ways to increase coal exports is to increase the total market for coal. Converting existing oil-fired boilers to burn solid coal is very expensive and also results in a loss in boiler capacity. As oil prices have stabilized temporarily, the longer indicated pay-out time required precludes utilities from making this investment especially in older boilers with short useful lives remaining, even if the capital could be raised by the utility.

Methacoal can be burned in existing oil-fired boilers with only a modest conversion cost for new burners and controls and with a minimum of derating or loss of boiler output. Limited data obtained in 100 Horsepower and 700 Horsepower boilers in Department of Energy burn tests conducted at the Pittsburgh Energy Test Center over the past two years showed that boiler efficiency is maximized and derating is minimized using Methacoal compared to coal-water mixtures. Long term tests to demonstrate the effect of deposit build-up due to the presence of ash are still needed.

The second way to increase competiveness of U.S. coal in world markets is to decrease delivered cost. It has been observed that transportation and handling costs for exporting coal can be greater than the mine-mouth cost of the product itself. The ability of Methacoal to reduce transportation costs and improve delivered quality at the same time are reasons why we believe Methacoal is so very cost competitive.

Methacoal reduces transportation costs in several ways. By pulverizing coal at the mine-site in the presence of methanol, moisture, sulfur compounds present as pyrites and some ash can be eliminated.

This means that instead of paying for shipping non-combustibles we pay for transporting more useful BTUs. This carries through for the whole transportation system wnere handling costs at export and import ports adds to the delivered cost.

As a side benefit, but also a very important one, by extracting moisture from coal at the mine, Methacoal can be produced in arrid areas usually with no local water required. In areas where high moisture coal is prevalent, excess water above processing needs can be returned to local use for irrigation and for use in land reclamation. The potential for converting high moisture coal to Methacoal and transporting long distances by pipeline without having to utilize any of the local water supply has an obvious advantage over coal-water slurries.

The need for expensive water washing and the loss of fine coal particles which are currently being sent back to waste ponds with the wash water would be eliminated. Conservative estimates indicate that 20-30% of coal now being mined is lost and rejected to the spoils where they impose a further energy penalty in their disposal. Methacoal creates an immediate increase in BTU production from existing mining operations without adding expenditures in capital or energy. This would also result in a lower impact on the local environment which under current operations has the potential of polluting the local water table.

Handling Requirements

Methacoal when handled in the above manner is of course flammable but only mildly explosive. Methacoal is safer to transport than gasoline or liquified gaseous fuels. To prevent the Methacoal from increasing in viscosity, evaporation of the methanol must be prevented by using an air-tight system, the kind currently employed with other volatile products like light crude oil, gasolines, light solvents, and methanol itself. This precaution regarding evaporation of course must also be followed for coal-water slurries, while not flammable, would become impossible to pump if too much water evaporated.

All phases of the current petroleum distribution system can handle volatile products if this is known as a requirement. In the case of oil-fired boilers, it means a change of thinking from handling a heavy fuel oil requiring heat to keep the oil flowing especially in cold weather, to one requiring no external heat and even in cold ambient temperatures requiring no boiler pre-heat. We see no insurmountable problems in adapting current oil distribution systems to handle Methacoal. Results at P.E.T.C. and other research facilities indicate a considerable advantage in handling coal-methanol suspensions compared to coal-water slurries. While Methacoal can be burned in oil-fired boilers with only relatively minor modifications of combustion equipment, in some cases the addition of soot blowers, sulfur scrubbers and particulate equipment may be required depending on the amount of sulfur and ash content remaining in the coal.

Methacoal Burns in Coal-Fired Boilers

Although oil-fired boilers may pose the greatest potential for the long term market, we believe the great flexibility offered by Methacoal suggests another important market as well. This can be of particular significance in view of the controversy surrounding the acid rain problem. Some critics accuse the solid coal-fired boilers, particularly in the midwest, of being the major contributors. Overseas, the Scandinavian countries likewise accuse the coal-fired boilers of Britain as the cause of their acid rain problems.

We believe that Methacoal can be used to reduce this acid rain problem as well. By transporting Methacoal to a solid coal user, simple evaporation can be undertaken at the boiler to separate the dry solids from the liquid stream. The dry solids, which we call CHC Fuel, can be introduced with or instead of normally pulverized coal. Because of the significant elimination of the mineral sulfides during the Methacoal blending process, a high sulfur coal would show a large reduction in sulfur content and therefore result in lower sulfur dioxide emission when burned and certainly less potential for forming acidic compounds when mixed with water vapor in the air.

In addition, limited tests have shown that the liquid portion, which we call Methyl Fuel, makes a very good turbine fuel and has already been approved as a fuel under the full warantee by a major U.S. supplier of turbine generators. A turbine generator can be installed in frontof a coal-fired boiler and fired with the separated Methyl Fuel. The result, when the turbine is operated in conjunction with the dry coal-fired boiler would be a significant increase in overall efficiency as well as an increase in generating capacity at a fraction of the cost of new coal-fired capacity and oil-fired capacity as well. For example, if a 25 megawatt turbine generator is placed in front of a 100 megawatt coal-fired boiler, the thermal efficiency would increase from approximately 32% to 40%. The cost of the turbine generating capacity is around $400 per installed kilowatt compared to over $1000 per installed kilowatt for a coal-fired boiler and somewhat under $1000 per installed kilowatt for an oil-fired boiler. Thus the use of Methacoal could produce a considerable fuel savings plus a savings in capital investment for additional generating capacity. If additional capacity is not required, the Methyl Fuel can be used for motor fuel as an extender with gasoline or in some cases as a chemical feed stock.

Demonstration Needed

The Keller Corp. is a very small, privately held R & D Corporation. Over the past decade about one million dollars has been spent on research and development and obtaining patents on Methacoal adding in U.S. Government, university, utility, and other researchers in industry~~,~~ that we know of. This does not include the nearly three years of pilot plant testing of Methacoal in Japan which is continuing under the support of the Ministry of International Trade and Industry (M.I.T.I.) organization of Japan. These data have not been made available to us but we have been told that the program will be continued for at least another year.

To convince potential customers to use Methacoal here or abroad, the need exists for a large scale demonstration of Methacoal and soon. We have been trying to do this of course, on our own or in cooperation with bonafide venture partners. We have recently entered into an agreement with Alaska Interior Resources, Inc. to work with them on the construction of a one million ton per year Methacoal plant to be completed in 1989 after a 5000 ton per hour methanol plant comes on stream in Alaska. Methacoal would be made from low sulfur, high moisture Beluga coal and the methanol made from North Slope natural gas as a feedstock. The market being aimed at is the Pacific Rim Countries but the U.S. West Coast would also be accessible. In the interim period, a mine mouth Methacoal demonstration plant is being considered to provide fuel for a 25 megawatt generating plant now burning pulverized coal. Unfortunately, because the surplus oil situation around the world has caused coal costs to be reduced to be competitive with lower oil prices, conversions of this kind are difficult to justify at this time on a strictly economic basis.

We have also been discussing an $18 million project with a Midwest utility to demonstrate the capability of burning Methacoal in a 50 megawatt oil-fired generating plant. However, because most of this particular utility's plants are coal-fired already, the incentive to demonstrate Methacoal in an oil-fired boiler has limited value to them. They are more interested in further work which would involve separation of the dry coal and burning it in a coal-fired plant. Expansion of the project to a full-scale commercial project which can show an economic payout even at today's lower oil prices can't occur before the demonstration phase is completed.

Included in the scope of the commercial project is to convert the Methacoal demonstration plant to an ethanol plant operating on the waste heat from a large methanol plant that would be constructed during the commercial phase of the project. Using the ethanol produced, Ethacoal could be produced at a cost competitive with Methacoal and would provide a market for substantial amounts of distressed or surplus grains.

Other projects have been considered. Where an economic incentive can be shown and a commercial venture identified, we keep running into the same question- where has Methacoal been proven in a long term test? If we are to interest potential customers in the export market, a large scale demonstration project in this country is essential.

Summary

May we conclude by leaving you with these thoughts. Coal is our most abundant resource. Methacoal makes available the cleanest, most efficient way to mine, process, transport, and burn that coal with a minimum capital conversion cost and with a maximum efficiency in existing boilers regardless of the temperature. What's needed to permit this development to be utilized by industry and utilities here and abroad is a meaningful demonstration as soon as possible to provide the confidence to convert existing plants to use Methacoal.

Tax incentives have been considered and to date have not seemed to help sell a Methacoal demonstration project. Apparently better tax shelters with less risk were available. The reduced cost of oil and gas has reduced the liklihood of making capital investments for alternate fuels which pay-out in a short time frame. If Congress eliminates the tax benefits inherent in lease-back arrangements as is currently being discussed but permits those projects which involve alternate fuels to continue to receive these benefits, perhaps some progress could be made in attracting venture capital. Perhaps permitting the interest payed on industrial bonds to be tax-free when invested in alternate fuel projects might help attract investment capital. Other areas of tax incentives might be feasible but are better left to those who have the expertise in this area.

Although much effort is being spent in developing coal-water slurries because of its expected lowest cost on a BTU basis, Methacoal has been shown to provide better performance on carbon conversion and boiler efficiency. Methacoal suspensions can be made out of even poor coals containing high moisture content. This is particularly important to less developed nations having inferior quality coal resources in their backyards. The possibility of cleaning coal at the mine-site by using Methacoal Technology offers hope for a large reduction in transportation costs even using existing modes of transportation which are a significant part of the export cost of coal. The flexibility of separating the liquid from Methacoal at the user location and burning solid, dry coal in coal-fired boilers in conjunction with turbine generators fueled with Methyl Fuel, suggests that the final economic judgement will depend on individual circumstances of coal source and customer requirements.

We believe that Methacoal Technology meets the goals of this hearing as described by our Chairman. Methacoal can increase domestic coal consumption on an environmentally sound and acceptable basis. Using more coal will make the United States more energy independent, improve our balance of payments, and aid our domestic economy by putting more miners to work and provide the means to construct more capital projects with the attendant work force requirements they would entail. Where less developed nations have a coal resource that can be developed, Methacoal Technology will permit the rapid development of this resource using existing infrastructure developed for the use of oil which in most cases has had to be imported at the cost of balance of payments deficits and loss of employment in that country. Brazil comes quickly to mind.

The need to develop new technology to enhance our ability to market coal has vital implications for the economy of the U.S. and the world. Although there is an apparent temporary oil surplus, the oil resources which abound in the Middle East continue to be in great peril. Iran has threatened to stop shipments of oil through the Strait of Hormuz if Iraq endangers Iran's oil capability in any way. The U.S. has warned that military force would be used if necessary to maintain a free flow of shipping in the Persian Gulf. The unstable situation in Central America certainly suggests that no oil source in Latin America is secure even though civil unrest in Central America has not yet spread to South America.

We are living in a world of turmoil with many areas currently engaged in open hostilities around the world. U.S. energy independence may be a key to achieving world stability. If we in the energy field can show the world that coal can take the pressure off oil for the long term, our statesmen may then get the time needed to work towards achieving the world peace we all desire.

Thank you for giving us this opportunity to present our Methacoal story to you today.

Senator WARNER. Very interesting statement. I thank you. Ladies and gentlemen, we have one more witness. I want to thank this panel and the gentleman is going to represent the rail system. Thank you, gentlemen.

STATEMENT OF WILLIAM HOPKINS, GENERAL COUNSEL, VIRGINIA RAILWAY ASSOCIATION

Mr. HOPKINS. Senator Warner, I want to thank you for the most informative panel that I have attended on coal since I have been employed by the railraod for this past year as a special counsel to represent them on continuing legislation on utilization and more, utilization of Virginia coal. I didn't go to that little school that Mr. Crews talked about, Western North Carolina. I, like you, am a graduate of Washington and Lee University, so I'm not sophisticated. [Laughter.] I won't make a claim on that. I do want to just correct, I talked to Mr. Sindelar about 2 weeks ago about this panel and he indicated this area would not be an issue and I indicated that I certainly didn't want to be on the panel but that I would like to comment. Accordingly, I do not have prepared remarks. I would just like to comment on a few things.

Senator WARNER. It was the chairman's intention today that that issue, which is a very important one, was not be injected into the hearing.

Mr. HOPKINS. Yes, and rightly so. First, I want to correct about the law in Virginia that says ther cannot be a pipeline. There is not such a law. There is a law in the utility section of Virginia which pertains to telephone companies, electric power companies, and railroads that says that the right of eminent domain shall not be used. That is condemnation, taking one man's property to build a slurry pipeline shall not be used by any utility other than the railroad. That was put in there in 1962 and at the time it was asked for by most of the Virginia coal operators. There was a move on in West Virginia whereby they were going to build a coal slurry pipeline from Fairmount, WV to Alexandria, to the port, Alexandria. And the West Virginia Legislature in 1962 passed eminent domain for West Virginia to build that coal slurry pipeline. Most of the Virginia coal operators, except for those of Mangohick (sic), with that move in West Virginia. The others with the railroads together with unit facilities approved of that amendment at that time and, in the cities of Virginia, there was absolutely no opposition.

Senator WARNER. You were there?

Mr. HOPKINS. I was there at the time and the United Mine Workers did support that legislation both in Virginia and in West Virginia. Now the United Mine Workers are opposing the coal slurry legislation in both. Really it came as a surprise to me that the genesis of this movement, as far as intrastate, would come from Vepco. Because in 1968, the Columbia Gas Co. has a number of sponsors in the Senate of Virginia to sponsor legislation that would permit the gas companies to have their own generators and thereby have total energy programs primarily starting in northern Virginia, whereby they could have a total energy program that would take a whole subdivision or it would take a shopping center or an industry. At that time gas was cheap and, in addition to heat, they could have air conditioning, lights, the whole bit. That measure came up before the Senate of Virginia. Justin Moore was one of those who came and testified very strongly against it, even though Vepco was the owner of the gas company, at that time. Appalachian was very strongly against it. It was the only time that I can recall that the chairman of the State Corporation Commission, Lester Hook, would take it upon himself to come to testify. They had him and they had financial analysts to say that this was a terrible destructive measure in the whole field of public service corporations. It was destructive for this reason: It allowed one utility, one group, to come in and skim off the cream of another utility's or public service area. Therefore, when the public utility electric power company would have to go and look to the homeowners who are less productive, where they have to serve everybody. And this was very destructive. That measure was killed in the Senate Finance Committee and it never got the floor although it had some very strong sponsors in northern Virginia. On a national scale, that is basically the coal slurry. When you put it on a national scale, that's basically the same principal involved. Really the genesis for this, the coal slurry and where the money and all is coming from are those who have large holdings in the Powder River basin whereby they don't mine the coal, they gather the coal at a cost of lesst than $10 a ton. They are selling it right now for less than $10 a ton. Anywhere from $5 to $10, based on the Btu count. Royal Shell which is half owner of Massie Coal Co. of Virginia which has large holdings out there and other large companies that have holdings there, and they are the ones that say that we should skim the cream from out there and put the coal slurry in, bring the western coal to make it more competitive with the eastern steam coal and get markets in the Texas, Arkansas area. There are some places in the East that I think that a coal slurry pipeline may be economically feasible. They are not in Virginia. There have been studies made by the Bureau of Mines in 1975 which made an analysis of coal slurry pipelines vis-a-vis unit train. What these coal slurry advocates do is thay try to take the single car rate of a train and measure that against what a coal slurry rate would be. They don't want to be basic, apples against apples or oranges against oranges. And consequently they know that as far as Virginia is concerned, its not economically viable. By studies that have been made by putting the coal slurries up against the unit train. The Office of Technology Assessment has a graph on—Office of Congressionalized Technology Assessment—has a graph on page 32 of its 1978 report which shows that from 400 miles out and under, that regardless of the tonnage the unit train is economically more viable than the coal slurry. It's only when you get the heavy tonnages and the long distances where the coal slurry comes into the competitive situation with the unit train.

There have been other studies but there has been no study that's been presented to Congress that refutes the basic information that's included in the Bureau of Mines report or in the Congressional Office of Technology Assessment, as to the two. The proof of the pudding, really, is in the tasting. We have here in Virginia, in fact, Norfolk and Southern has two unit trains. One comes out of Martin County, KY. And the unit train is based on the same theory as a slurry pipeline. You gather your coal at one point, you ship it to another point. They gather it in Martin County, KY, they take it 344 miles to a Duke powerplant, it is 6 million tons per year. It was provided for in the 1970's, no Federal slurry caused it, by a contract. They put that, hauled that coal at 2.45-cents-per-ton mile. Based on all economic data that we have thus far and studies by the Bureau of Mines and the Offices of Congressional Technology Assessment, the coal slurry cannot meet that unit cost at a distance of 400 miles or even 500 miles. In Virginia we have the same concept, that's in Appalachia, Wise County, where we have the transloader there. Actually, it gathers it at a point in Appalachia and take the coal to two powerplants in North Carolina, and they go on a continuous basis. Last year, 3,065,000 tons were shipped at a cost of 2.2-cents-per-ton mile to one plant and 2.3-cents-per-ton mile to the other, a cost that a slurry cannot meet on that distance.

Senator WARNER. Would that be an operating cost or a capital cost, or a combination?

Mr. HOPKINS. That's everything. For slurry, to answer your question, we would take an operating cost and you amortize capital cost over a 30-year period which they say is the useful life of the two, of the slurry. So, its operating cost plus amortizing the capital cost over 30. And I'm talking about cost. But now, we make a profit. The railroads make a profit on that.

Senator WARNER. I think the coal producers will testify to that. [Laughter.]

Mr. HOPKINS. That's right. Well, I don't know on that low rate but because it's the most efficient way of hauling coal. The inefficient way, of course, is where you have to pick up 1 car or 2, 10 cars here, and deliver it to another place and then, of course, the costs escalate. However, the cost in Virginia of the 15 cents plus per mile plus 50 cents loading plus the 16–35 on the steam coal, still from 400 miles and aboard ship, is the lowest cost in this country for having shipped on board and getting it, and that's a per car rate.

Senator WARNER. What's the distance from Wise County to Hampton Roads?

Mr. HOPKINS. 400 miles.

Senator WARNER. 400 miles, give or take?

Mr. HOPKINS. Yes, give or take, it's in there. So basically what we are talking about here in Virginia—and you're talking about slurries, and you're talking about steam coal. Practically all of the Virginia's coal is met coal, metallurgical coal. Met coal brings $10 to $30 per ton over a 5-year period, premium over steam coal. Regardless of the quality, the high quality of the steam coal. The coal in Virginia has an average moisture content of less than 3 percent, of 2.9. By the time you wash it, it goes above that and it gets into Norfolk at 5–6 percent, in that area. Btu slurry coal is a 10 to 12 percent. Your coal contracts in overseas where you increase your moisture it lowers the Btu and we make a discount. So in order to have a coal slurry unit in Virginia, first you've got to go to a group. There are 881 mines in Virginia, licensed mines, not all operating at this time, licensed mines but most of them are small. You have to go to a group and say, "Look, you take a $10 to $30 discount up front on your coal for a period of 20 to 30 years." Then you say, "At the terminal point, you take another $4 to $5 discount because of the moisture content." A double discount. You have ruined the quality of your Virginia coal. Then you've got to tell him, "It's going to cost you more to transport." If they can locate a 5 million ton—if Vepco can locate a 5-million ton that can be gathered in one point today, redeposit another 5 million tons a day in Virginia, the Norfolk & Southern can transport that on a unit train for less than the operating costs of a coal slurry plus amortizing costs over a 30-year period, the capital costs. It could do it at 10,000 tons, it could do it at 15,000 tons, and according to the Congressional Office of Technology Assessment, and that graph goes all the way up to 40 million tons, it can do it at 40 million tons.

Senator WARNER. Mr. Hopkins, that's a pretty positive statement. If you'd like to supplement the record, we'd be happy to do so.

Mr. HOPKINS. Thank you.

Senator WARNER. We've caught you a little unprepared, but you know your subject and I thank you. And ladies and gentlemen, I thank all of you who have participated in this hearing and we appreciate it very much.

[Whereupon, at 5:30 p.m., the hearing was adjourned.]

APPENDIX

Additional Material Submitted for the Record

integrated

David R. Williams, Jr.
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August 5, 1983

The Honorable John W. Warner
Chairman, Subcommittee on Energy
and Mineral Resources.
Committee Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

I am submitting this letter and attached paper pertaining to Purged Carbons™ for consideration by you and your Subcommittee in connection with your scheduled hearing on "Enhanced Coal Technology - Coal's Market for the '80's", which was originally scheduled for July 16, and was rescheduled for August 9. The subject of the hearing is of great interest to us, and we felt that your Subcommittee would be interested in the Purged Carbons™ technology, which has the potential of replacing foreign oil on a large scale, at an early time and at a competitive price.

While a more complete description of the Purged Carbons™ program is contained in the attached paper (entitled "Technical and Process Description"), I would like to address briefly in this letter a few of the essentials of the product, its process and benefits.

Purged Carbons™ is a clean hydrocarbon fuel derived from coal and designed to replace liquid petroleum products. It is produced by the application of hydrofluoric and hydrochloric acid to sand-sized raw coal which removes virtually all inert material matter (i.e. ash). The process is being developed to remove also about 90% of the sulfur, substantially eliminating sulfur dioxide emissions, and combusts at temperatures expected to reduce or eliminate nitrous oxide. Purged Carbons™ could be burned in existing coal, oil, gas, or diesel applications without expensive retrofitting or use of scrubbers and precipitators, and at the same time contribute to achieving our clean air goals and reduction of acid rain.

The finished product can be stored and transported in either dry form or liquid slurry mixture, and can be transported in barges, tanks, or pipelines.

The purified product can be directly applied as a substitute for oil. Potential uses include boiler fuel; for instance Purged Carbons™ can displace #6 fuel oil in utility and industrial boilers. The substantial potential for this use is apparent. Purged Carbons™ is potentially valuable in national defense as a military fuel, where its benefits include domestic availability, and when used in military vehicles, a high resistance to explosion upon impacts. The process also has potential for producing other non-fuel by-products, such as activated carbons, carbon black, and possibly graphite, among others.

Another major benefit of the Purged Carbons™ process is that it can be applied to all U.S. coal supplies, whether high sulfur or low sulfur, Eastern or Western, bituminous or subbituminous. Processing plants can readily be developed in any of the Nation's coal-producing areas, allowing for dispersal of facilities and the attendant economic and employment (as well as defense) benefits. The process may aid in the development of coal supplies previously considered too remote or uneconomic to produce.

Integrated Carbons Corporation expects that with sufficient developmental support it can produce Purged Carbons™ on a commercial scale within this decade, beginning at a rate approximately equivalent to 60,000 barrels of oil a day and escalating rapidly from there, depending on the number of plants built.

We believe that environmental impacts of the production process can be kept to a minimum. Acids will be produced on-site and will be recycled, so there will be no problems of transportation of acids to and from the plants. There will be no liquid waste stream from the Purged Carbons™ process. The only outputs of the plants will be Purged Carbons™ itself, combustion gases, and ash residue. The basic technology is known and can be controlled. During the second stage of the development program, upon which we are now embarking, we will be monitoring very carefully all aspects of the operation, emissions and products, to assure a safe process and cost competitive product once commercial scale is attained.

Upon completion of the development process, we fully expect that we can supply commercially a coal-based oil substitute for a cost in the range of $3 to $4 per million Btu, well below even the current cost of oil. The cost advantage should increase with time.

Recently, the Integrated Carbons Corporation completed Stage I of the Purged Carbons™ developmental program at a cost of over $2 million, borne entirely by the Company. Stage I focused on batch process development, patent work, and economics. Stage II of the developmental process is just now underway, and assuming the availability of adequate and timely funding, will focus on the continuous operation of the process, further refinement of economics, and further data gathering with respect to such issues as materials handling, transportation, potential product uses, and environmental impacts. Stage II is expected to cost over $7 million and take 18 months to complete.

Hazen Research, Inc. of Golden, Colorado, the largest independent hydrometallurgical research firm in this country has evaluated the Purged Carbons™ process as having the capability of producing a coal-based fuel which can be directly substituted for foreign oil in many applications; which can be produced for substantially less than the current price of oil; and which could be commercialized within this decade.

The Purged Carbons™ product has great potential for making use of the nation's vast domestic coal resources in meeting its future energy needs, while reducing its dependence on foreign oil and achieving air quality standards. We are excited by the possibility of assisting the Nation in achieving the important goals of the Energy Security Act of 1980 (PL-96-294), to achieve energy security for the United States for the health of the national economy, the well-being of our citizens, and the maintenance of national security, in a manner consistent with protection of the environment.

We are aware that many alternative energy approaches exist, but few offer the potential of early commercialization, use in existing facilities without expensive retrofitting, or an effective solution to SO_2 and NOx emissions, or product costs which can compete with oil at today's oil prices. The Congress has recognized the strategic need for alternative fuels and has allocated billions for its development. We have a technology which we think might be the answer but requires capital, which is not available today in sufficient amounts from the private sector, to complete its development. The U.S. Synthetic Fuels Corporation has advised, without addressing the viability of the technology, that the technology does not meet the maturity requirements of their program. While we continue to fund our process development with our own resources, we would welcome any suggestions from the Committee as to how our technology might be evaluated in the context of its potential to our country and appropriate assistance obtained.

Respectfully submitted,

David R. Williams Jr

David R. Williams, Jr.

DRW/cva

Enclosure

July, 1983

TECHNICAL AND PROCESS DESCRIPTION

DESCRIPTION OF THE PRODUCT

Purged Carbons™, derived from coal, is a pure hydrocarbon fuel designed to replace liquid petroleum products. It is the transformed coal matrix which remains after the inorganic mineral matter (ash) is removed (purged) by extensive chemical processing. Environmentally, this pure-coal substance is comparable to fuel oil. Additionally, the process can produce significant quantities of alumina as a commercial by-product.

Sand-sized coal is contacted with acids dissolving mineral matter and leaving Purged Carbons™. At this size, 1/2-mm by zero, the purified product can be transported either as a slurry in pipelines or as a dry product into and out of barges and tanks by pneumatic methods. For burning, Purged Carbons™ would be further pulverized and fired dry, as is common in coal-fired boilers, or as a coal water slurry. A more finely ground Purged Carbons™ can also be prepared to fire gas turbines as well as diesels. Additionally, Purged Carbons™ is a suitable feedstock for carbon black, electrode carbon, and activated carbon.

PROCESS BASIS

Clays (aluminosilicates) comprise the major impurity associated with coal measures, and the only substance which dissolves aluminosilicates at room temperature and pressure is hydrofluoric acid. Yet, hydrofluoric acid does not attack hydrocarbons; in fact, in years past it was kept in wax bottles, now plastic. The high cost of hydrofluoric acid ($1,400 per ton) kept the acid from being employed in commercial coal processing. Now, however, Integrated Carbons has coupled the unique dissolving power of the acid with a highly acid recovery scheme developed as an off-shoot of the phosphate industry. That recovery scheme produces alumina as a by-product.

PROCESS DESCRIPTION

The process steps for an Eastern bituminous coal (processing is similar for western subbituminous coals) are:

- Coal sizing and preparation
- Hydrofluoric and hydrochloric acid leaching
- Acid regeneration
- Tabling for pyrite removal
- Washing the Purged Carbons™
- Drying the product
- Coal/water slurry formulation

All acids are made on-site to preclude the potential hazards of shipment. Raw materials for the process are:

Coal	Salt
Fluorspar	Limestone
	Water (at a fraction of that required for conversion)

PRODUCT ANALYSES

Typical product has the following analyses:

Ash	0.15%
Heating Value	13,000 to 15,000 Btu/lb
Total Sulfur	0.2 to 0.8%

THE PURGED CARBONS™ PROCESS AND ITS POTENTIAL TO FULFILL THE INTENT AND THE SPIRIT OF THE ENERGY SECURITY ACT

The intent of Public Law 96-294, the "Energy Security Act" is clear -- to achieve energy security for the United States essential to the health of the national economy, the well-being of our citizens and the maintenance of national security through attainment of synthetic fuels production in a timely manner and in a manner consistent with the protection of the environment.

The Energy Security Act further establishes a national synthetic fuels production goal which is as follows:

> "...production capacity equivalent to at least 500,000 barrels per day of crude oil by 1987 and of at least 2,000,000 barrels per day of crude oil by 1992, from domestic resources."

The United States Synthetic Fuels Corporation has issued three solicitations and received in excess of 100 proposals in response to the first and second solicitations.

The United States Synthetic Fuels Corporation has not negotiated any contracts for assistance to date. The apparent reason for this is that of the proposed projects each have one or more of the following deficiencies:

- Uneconomic based on current and/or projected world oil price levels.
- Capital requirements are so great that original project sponsors cannot fund the project by themselves and are unable to attract necessary additional equity partners (capital).
- Potential technological uncertainties.
- Potential environmental uncertainties.
- Project is difficult to replicate due to siting, engineering, construction and environmental contraints.

Even if the United States Synthetic Fuels Corporation were to grant financial assistance to the 11 projects still under consideration from its first and second solicitations --
the 1987 production goal of 500,000 barrels per day would not be attained.

It is now apparent that for the United States Synthetic Fuels Corporation to fulfill the goals set in the Energy Security Act, it must reconsider both the technologies selected for consideration and the form of financial assistance (consistent with Public Law 96-294) available to potential project sponsors.

THE PROBLEM

Billions of dollars have been spent both by the private sector and Government to find a suitable domestic replacement for foreign oil. Whether the proposed technology solution was nuclear, renewable resources or synthetic fuels, success has been limited for technical, economic, health and safety and/or environmental reasons.

Because our nation's industrial and transportation infrastructure is based on obtaining energy from relatively clean oil and natural gas, most synthetic fuels development efforts have focused on subjecting relatively dirty solid hydrocarbons to high temperatures and pressure in an attempt to transform them into clean liquid fuels. Commercial plants capable of such high pressures and temperatures feature:

- Massive capital expenditures.
- High energy losses in transforming a solid into a liquid.
- Large water requirements.
- Environmental uncertainties in regard to the disposal of waste material (air, liquid and solid wastes).

In addition, many projects have been temporarily shelved or canceled because final product costs are currently above world oil price levels, future energy price forecasts are uncertain, and construction cost estimates are subject to unknown inflationary pressures.

The Exxon/Tosco Colony Project is a case in point. The Exxon decision to proceed with Colony utilizing the Tosco II Process was based on a feasibility study which concluded that a 50,000 barrel per day plant could be constructed for $3.2 to $3.8 billion dollars and the product from this plant would be competitive with $34 per barrel crude oil. When world oil prices fell below $34 per barrel and Exxon Research in New Jersey recalculated project costs at approximately $6 billion dollars, Exxon withdrew from the Colony project.

THE SOLUTION

Three challenges must be met by any synthetic fuel which can seriously be considered as an alternative to oil and natural gas. The synthetic fuels must:

- Have favorable cost relative to oil and natural gas.
- Be substitutable for petroleum and natural gas in the country's industrial and transporation infrastructure.
- Meet current environmental standards.

The Purged Carbons™ process appears capable of meeting all of these requirements using a radical but logical departure from the conventional attempts to convert a solid feedstock to a liquid or a gas.

The product, Purged Carbons™, is a hydrocarbon fuel derived from coal and will replace liquid petroleum products and natural gas. It is produced by transforming coal through a series of physical and chemical processing steps. These steps remove the mineral matter from the coal matrix leaving a solid hydrocarbon product. A short process description appears in Attachment II. The product is 1/2-mm by zero size and can be transported as a dry product by pneumatic conveying or as a slurry in pipelines.

Purged Carbons™ has been successfully produced in the laboratory and in a pilot plant. The process removes more than 90% of the pyritic sulfur contained in the feedstock and the final Purged Carbons™ product from most coal feedstocks contains less than .15% ash. This means that on an absolute basis, Purged Carbons™ is as clean or cleaner than many fuel oils. (Additionally approaches the removal of organic sulfur).

Purged Carbons™ can potentially be substituted for a variety of fuels. The most important of these are:

- Boiler Fuels -- Purged Carbons™ can displace #6 fuel oil in utility and industrial boilers which were designed for oil.
- Gas Turbines -- Purged Carbons™ can potentially be substituted as the primary fuel for combustion in turbines.
- Diesel Fuel -- Purged Carbons™ potentially can be prepared to fuel diesels used in power generation, marine and railroad applications.

In addition to fuel uses, Purged Carbons™ has many non-fuel uses, including substitution for activated charcoal, carbon black, electrode carbon and feedstock for the manufacture of graphite.

The Purged Carbons™ process is proprietary and is different from any technology presently under consideration by the United States Synthetic Fuels Corporation. Moreover, it is the only technology which is based on chemically altering coal at ambient temperature and pressure.

A. FAVORABLE COST

An independent economic study of the Purged Carbons™ process by Hazen Research, Inc. concludes that a Purged Carbons™ plant capable of producing a 60,000 per day oil equivalent could be constructed for in the range of $320 to $400 million dollars. In comparison to the Colony project, the Purged Carbons™ capital costs are as follows:

Project	Capital Cost Range, $ Low	 High	Plant Output (Oil Barrel Per Day Equivalent)
Colony	3,200,000,000	6,000,000,000	50,000
Purged Carbons™	320,000,000	400,000,000	60,000

Under the worst case comparison, the Purged Carbons™ plant would produce slightly more product than Colony at one-eighth the projected capital cost. In the best case comparison, the Purged Carbons™ plant would produce slightly more product than Colony at one-eighteenth the projected capital cost. A reasonable estimate is that the Purged Carbons™ plant will produce the same barrel per day equivalent as Colony, at one-tenth the projected capital costs.

The Hazen report indicates that the Purged Carbons™ can be produced and formulated into a coal water mixture for $2.51 mm/Btu. This is substantially below the current depressed oil and diesel oil prices.

Purged Carbons™ commercialization may mean that large central stations need not be constructed. Turbine-combined cycle units using Purged Carbons™ as the primary feedstock could take the place of central station power stations. At $450 per kilowatt installed, gas turbine-combined cycle units cost but a fraction of the $1400 per kilowatt that new coal units cost today. Utilities (which use 80% of all coal mined in the U.S. today) could pay as much as $7 per million Btu for this fuel and still provide power competitively with new coal plants burning coal costing as little as $1 per million Btu (a delivered cost of $20/ton of a 10,000 Btu/lb coal would equal $1MM/Btu).

On the basis of the above, Purged Carbons™ today has favorable costs relative to oil and natural gas and the relative costs should improve in the future.

Congress recognized the importance of production potential in the Energy Security Act as delineated in Section 131 (b) (3) (B) (II):

> "the overall production potential of the technology, considering the potential for replication, the extent of the resource and its geographic distribution, and the potential end use..."

B. 1. PRODUCTION POTENTIAL OF THE TECHNOLOGY

The independent economic study conducted by Hazen Research concludes that after all final design/engineering is accomplished, a Purged Carbons™ plant can be constructed in twentyfour (24) months. Thus, if Integrated Carbons obtained financial assistance now, a commercial plant could be in production in early 1988, capable of producing 60,000 barrels of oil equivalent per day.

Integrated Carbons and other potential Purged Carbons™ producers will need time to assess the plant/process technically, operationally and economically. Assuming a one year period for potential investors to complete such evaluations, commitments for additional plants will be made in late 1986. On this basis, it is forecast that as many as twenty-nine (29) plants will be operational in 1992. Only one of these plants -- the first plant -- will require United States Synthetic Fuels Corporation financial assistance. The scenario for how this will occur is presented in the table below:

Year	Commitment Of Finacial Assistance By USSFC Number of Plants	Commitment By Private Sector To Build Purged Carbons™ Facility Number of Plants	Purged Carbons™ Plants in Production Number of Plants	Barrel Per Day Oil Equivalent Produced of Purged Carbons™ Plants
1983	1			
1984	-			
1985	-		-	
1986	-	-	-	
1987	-	-	-	
1988	-	4	1	60,000
1989	-	8	1	60,000
1990	-	16	5	285,000
1991	-	N/A	13	741,000
1992	-	N/A	29	1,653,000

Thus, the Congressional objective of attaining the production from domestic resources of the equivalent of at least 2,000,000 barrels of crude oil per day of synthetic fuels by 1992 might be significantly impacted -- 83% attained with the following favorable benefits to the Government and the United States:

- A United States Synthetic Fuels Corporation commitment to provide financial assistance to only one plant -- the initial plant.
- A risk exposure to the Government not in the billion dollar range but in the $500 million dollar category.
- Commercialization of a technology where multiple plants can be constructed in two years, as opposed to five, seven or ten years (the above schedule could be accelerated in case of a national emergency).

2. POTENTIAL FOR REPLICATION

Purged Carbons™ offer a significant advantage in that plants can be located at all major coal fields and are easily replicable. This is the case for the following reasons:

- Purged Carbons™ can utilize almost any coal existing in the United States.

- The process does not require high temperatures or high pressure.
- Most equipment and instrumentation required for Purged Carbons™ plants are currently available from existing manufacturers.
- Plants will be modular -- major components will be fabricated at a central location and shipped via barge, rail or truck to operating sites. Local labor can be used for erection.
- Space requirements are small in comparison to other known synthetic fuels technologies.
- The process recovers more than 99% of the energy originally contained in the feedstock (although approximately 4% is consumed as process heat).
- Depending on the moisture content of the feedstock used, the process requires either minimum amounts of water or is a net water producer.
- Waste effluents are benign and SO_2 and NO_x stack emissions are mitigated so as to be minimal. This will avoid the grave problems arising from sulfur emissions, such as acid rain, which, among other ills, has been recently connected to breast cancer in women.

3. EXTENT OF THE RESOURCE

Purged Carbons™ can utilize most coals existing in the United States. The coal resource base in the United States represents 90% of our known hydrocarbon energy resources.

4. POTENTIAL END USES

Purged Carbons™ will allow coal to enter the higher end of the fuels market heretofore available only to oil and gas. This product is not intended to capture markets already served by conventionally prepared coal in coal-fired applications, but rather represents incremental coal demand created by shifting away from firing oil and gas. This incremental demand logically translates into increased employment in coal mining and related industries.

Purged Carbons™ also offers a distinct advantage in terms of marketing the end product. Oil shale, tar sands and many coal gasification projects must be located in geographically limited areas. For instance, due to current resource and technology constraints, shale oil production appears to be limited to Western Colorado, Eastern Utah, Southern Indiana and Northern Kentucky. Unfortunately, these are not the major petroleum consuming markets. Serving major markets outside these areas will result in high distribution costs.

By contrast, Purged Carbons™ plants can usually be located anywhere in the United States where appropriate coal resources exist. This means that Purged Carbons™ plants can be located near major consuming markets resulting in lower distribution costs.

In addition to the production of a coal-based energy source, the Purged Carbons™ process may produce enough alumina to supply the United State's requirements of this strategic import.

C. ABILITY TO MEET CURRENT ENVIRONMENTAL STANDARDS

The Purged Carbons™ process utilizes coal as its primary feedstock. Other important raw materials are sulfur, limestone, fluorspar and salt; all of which can be contained safely within the system and are not emitted into the environment.

Air emissions and liquid and solid wastes are produced in a Purged Carbons™ plant. All emissions and wastes can be controlled, treated or disposed of using known environmental control technologies and procedures. The Purged Carbons™ process is dependent upon known hydrometallurgical practices. Consequently, the character of emissions and wastes can be predicted unlike many synthetic fuels technologies which produce wastes of unknown compositions and characteristics.

Coal cannot be mined and processed without environmental impact, but when the end product is Purged Carbons™, there is a clear net environmental benefit over the conventional mining and burning of coal. From a processing point of view, Purged Carbons™ has substantial environmental advantages over any known solid or liquid process. The only products of a plant are steam, mineral oxides, and Purged Carbons™. It has similar environmental advantages when compared to any raw or processed coal on a combustion basis (specifically when SO_2 and NO_x emissions levels are radically reduced over conventional coal combustion).

The need for permits and environmental assessments is very site specific. Therefore, environmental permitting will be handled in conformance with the procedures applicable to a given location.

RELEVANCE TO OTHER ENERGY SECURITY ACT PROVISIONS

Besides fulfilling cost, production potential and environmental requirements which must be inherently favorable in the technology as well as meeting the requirements of the Energy Security Act, Purged Carbons™ potentially fulfills four institutional goals specified in the Act. These are:

- Production from domestic resources
- Different types of coal
- National security
- Balance of payments

A. PRODUCTION FROM DOMESTIC RESOURCES

The Energy Security Act in Section 100 continually refers to "production from domestic resources". Congress intended primary consideration to projects which would use the nation's abundant natural resources -- specifically coal, oil shale, and tar sands. Purged Carbons™ would result in a nationwide program that would use our vast coal reserves and significantly reduce our dependence on natural gas and imported petroleum products.

B. DIFFERENT TYPES OF COAL

The Energy Security Act, in Section 126 (a) (2) (B) states that:

> "...domestic resources shall be construed so as to require the consideration of different types and qualities of coal (such as high- and low-sulfur coal, or Eastern and Western coal),...as different resources."

Purged Carbons™ can be produced utilizing all types of coal which comprise the United States coal resource base; whether high- or low-sulfur; Eastern or Western. Purged Carbons™ can be produced utilizing coal from any and all States in which coal is available or can be transported economically. Thus, Purged Carbons™ has a distinct advantage in that plants can be sited wherever sufficient quantities of coal are available or can be transported. This means that almost any location in the United States can benefit from the construction and operation of Purged Carbons™ plants.

C. NATIONAL SECURITY

The Energy Security Act in Sections 100 and 102 delineates the purpose of the legislation and declares policy. Much of the purpose and policy centers around security considerations.

Section 100 (a) (1) states:

> "the achievement of energy security for the United States is essential to the...maintenance of national security."

Section 100 (b) (1) states:

> "The purposes of this title, and the amendments made by this title, are to utilize to the fullest extent the constitutional powers of the Congress to...increase the Nation's security by reducing its dependence upon imported oil"

Section 102 states:

> "...to respond to actions occurring outside of the United States which could result in the termination or reduction of the availability of strategic and critical materials, including energy, and which would adversely affect the national defense preparedness of the United States. In order to insure the national defense preparedness which is essential to national security, it is also necessary and appropriate to assure domestic energy supplies for national defense needs."

Purged Carbons™ can probably contribute more to the national security portion of the Energy Security Act than most other synthetic fuels. The reasons for this are the following:

1. Purged Carbons™ plants will utilize our nation's most abundant fossil energy resource - coal.
2. Purged Carbons™ plants will be geographically dispersed across the United States making it difficult for a potential enemy to destroy all energy production facilities.
3. The by-product of the Purged Carbons™ process, alumina, is a strategic metal. Thus, Purged Carbons™ offers an alternative and for the first time, a domestic source for this strategic metal.
4. Purged Carbons™ plants are easily replicable and can be constructed in a twenty-four (24) month period. Thus, the time necessary to gear up for a defense emergency situation is much less than for most other potential synthetic fuels technologies.

5. Purged Carbons™ has the potential to completely eliminate the requirement for imported oil in this century. Thus, through the use of Purged Carbons™, our nation would not be short of necessary energy during a national emergency.

6. Purged Carbons™ has the potential to be used as fuel in weapons systems. One potential application is as a tank fuel. The chief advantage of using Purged Carbons™ as a tank fuel is that if the tank takes a direct hit, the chances of explosion are minimized, thus sparing the crew and maintaining some of the weapons operating capability. It has also been suggested that Purged Carbons™' efficient weight-to-energy ratio would make it an excellent fuel for turbine-powered weapons, such as the cruise missile, where a short engine life obviates the conventional concerns centered around blade impingement and slagging when routinely dirty fuels are used.

7. The Purged Carbons™ process began as a metals recovery process. Because a wide range of strategic metals are contained in coal ash and all are in solution during the Purged Carbons™ process, it is anticipated that a number of commercial strategic metals by-products such as titanium will be extracted in second generation plants. Research concurrent with Purged Carbons™ commercialization could accelerate this eventuality if it were deemed of strategic importance and funding was made available.

D. BALANCE OF PAYMENTS

The Energy Security Act, in Section 100, states that the production of synthetic fuels to improve the nation's balance of payments is a matter of national policy.

Section 100 (a) (1) states:

> "the achievement of energy security for the United States is essential to the health of the national economy, the well-being of our citizens..."

Section 100 (b) (1) states:

> "The purposes of this title, and the amendments made by this title, are to utilize to the fullest extent the constitutional powers of the Congress to improve the nation's balance of payments..."

Purged Carbons™ can contribute directly to a more favorable United States balance of payments. Purged Carbons™ can be entrained in fluid mediums such as air or nitrogen thereby enabling transport and storage in systems designed for liquid fuels. For this reason, the introduction of Purged Carbons™ could allow high speed, deep water loading through the use of monomoorings. It is possible that tankers as well as colliers could be used for overseas shipping. The ability to use monomooring will eliminate the necessity for large expenditures and time delays to construct new port facilities which would otherwise be necessary to develop a large United States coal export trade.

Western Europe imports half and Japan nearly all of its energy requirement. Both have developed energy infrastructures based on oil and gas. As the principal trade partners of the United States, they have generated the excess currency required to buy oil through the innovative and agressive marketing of their products here. This has resulted in an imbalance of trade of such proportion that restrictive trade policies are now being considered by the United States Congress.

The Japanese have an interest in buying energy from the United States for several reasons. This would help address the awkward trade imbalance between the United States and Japan ($18 billion in 1981); and offer a more dependable source than OPEC. Coal is the one commodity of which the United States has sufficient supply to offset these trade imbalances, independent of other products or initiatives. Purged Carbons™ could facilitate this, and it could also help mitigate sensitive environmental issues in Japan.

Western European energy markets have been open to limited quantities of imported coal for some time. Through the introduction of Purged Carbons™, an incremental demand would occur as coal would supplant oil and gas in fluid designed infrastructures. The handling and shipping of coal has been a major obstacle to increased trade with Europe and as explained above, Purged Carbons™ potentially solves this problem.

Coal shipments to the Pacific rim countries from the United States have not yet met expectations due to the costs and logistics of delivery, as well as the ash and moisture content of Western U.S. coals. Dry, high energy Purged Carbons™ would allow this same coal to compete with higher grade liquid fuels saving the billions otherwise required to convert this market's facilities from oil and gas to conventional coal burning.

OWNERSHIP

Patents on and related to the Purged Carbons™ process are owned by:

Integrated Carbons Corporation
320 South Boston
Suite 831
Tulsa, Oklahoma 74103
(918) 582-5811

For further information concerning the Purged Carbons™ process and to potential benefits, contact Mr. Robert R. Horton, Executive Vice President at the address/telephone number referenced above.

CONCLUSIONS

Purged Carbons™ has the potential to become an important alternative to imported petroleum and to assist the United States in fulfilling the intent and spirit of the Energy Security Act.

- Purged Carbons™ can contribute significantly to meeting the United States Synthetic Fuels Corporation's production capacity equivalent goal of at least 2,000,000 barrels per day of crude oil by 1992 from domestic resources.
- Purged Carbons™ can be produced at a favorable cost relative to oil, natural gas and other synthetic fuels.
- The production potential of Purged Carbons™ will be exclusively from domestic coal resources and therefore is limited only by the extent of our Nation's immense coal reserves.
- Purged Carbons™ plants are easily replicable at dispersed locations throughout the United States.
- Purged Carbons™ will allow coal to enter the higher end of the fuels market heretofore available only to oil and natural gas.
- Purged Carbons™ has the ability to meet all existing environmental, health and safety standards.
- Purged Carbons™ will contribute greatly to fulfilling the national security objectives of the Energy Security Act.
- Purged Carbons™ has the potential to significantly favorably influence our Nation's balance of payments.

Department of Energy
Draft - June 24, 1983
Page 1

SUMMARY OF TECHNICAL PROGRAM TO ADDRESS, SO_2 NO_x AND PARTICULATE REDUCTION FROM COAL COMB

The process and economics for Purged Carbons™ were developed by independent researchers and consultants under the guidance and at the expense of Integrated Carbons Corporation. At the present stage of development, a ±30 percent level of certainty was ascribed to the process economics by Hazen Research, Inc., who developed them.

In the orderly pursuit of commercialization, Integrated Carbons has staged the work both in terms of the scale of operation and level of economic certainty; the stages are:

Development Stage	Major Activities	Scale of Operation	Potential Variability of Stated Economics
I. Batch	Process development, patent work, economics	pound batches (250 lbs maximum)	± 30%
II. Continuous	Continuous operation, data acquisition, patenting efforts, economics	3 tons/day (250 lbs/hr)	± 20%
III. Demonstration	Continuous operation, engineering date and verification, economics	120 tons/day (40,000/TPY)	± 10%
IV. Commercial	Engineering, construction, start-up, production	1- to 5- million tons per year	--

The first stage of development (Batch - Stage I) was essentially completed in April, 1983 at a cost to Integrated Carbons of nearly two million dollars as well as the uncompensated executive time of all but technical staff. The first stage has been evaluated as sufficiently promising to warrant Integrated Carbons' embarking upon the second stage of development (Continuous - Stage II), which is hoped will increase the economic predictability to a ± 20% level.

STAGE II

Achieving A Level of Certainty to + 20%

The information which is essential and must be acquired in order to complete the economics to the + 20% level is process data derived from a continuous plant operation. To that end, a small bench plant will be built and operated and the required data gathered, thereby enabling the economic study to be completed.

In addition, the transportation and utilization of Purged Carbons™ will be assessed at the same time that the process data are being secured. Purged Carbons™ will be produced on a batch basis at the outset of this development stage (Stage II) and dispensed to parties in both the public and private sectors who have already expressed interest in its performance in boilers, turbines and diesels. The early assessment of Purged Carbons™ product is critical because Purged Carbons™ is a totally unique product.

The company's patent counsel is Sheridan, Ross & McIntosh of Denver, Colorado. (Three patent applications have been filed to date. Another five are in preparation.)

The impact of Purged Carbons™ production, transportation and utilization on the environment, will be investigated so that appropriate tests can be executed to provide the information required. Additionally, all aspects of permitting will be described to enable merging technical and permitting activities without delays.

One year is required to complete all work needed to achieve a ± 20% level and meet the objectives of this stage of development; additional data descriptions regarding the above follow.

Continuous Three Ton/Day Plant

The objectives of this program are to:

1. Produce a fuel, continuously, which can be burned in compliance without precipitators or scrubbers.

2. Prove the technical feasibility of the process on a continuous basis including the reprocessing of recycle streams.

3. Provide engineering data, such as mass flows, analyses of plant streams, solid/liquid separation rates, corrosion and erosion data, etc.

4. Produce material for characterization including chemical analyses and other indicated testing. Of concern here are all plant discharge products; in addition to Purged Carbons™, there are mixed oxides (ash).

5. Corrosion and erosion studies.

The plant will have a feed rate of three tons per day which is 250 lbs/hr. It is planned to be disengaged at selected points for convenience. Comminution and beneficiation of the feed coal will take place at a time and rate independent of the leaching circuits. The resulting cleaned and sized coal will be stored in a bin until a later time when it will be sent to the leaching circuits, probably at a different rate. HF leaching, HCl leaching, washing, gravity separation and, if required, baking will be carried on simultaneously. Pregnant liquors from the leaching circuits will be separately stored, and the HF and HCl regeneration circuits will utilize these feed liquors probably in an open circuit that does not return the HF and HCl to their respective leaches.

Operation of the plant will be by campaigns. Operation will be on a 24-hour basis until some problem suggests a shut-down. During shut-down, operation will be on an 8-hour day. Plant streams and products will be analyzed, the problem isolated and fixed, and a new campaign initiated on a 24-hour basis. This mode of operation will continue until the plant can be run successfully, producing specification products for an extended period.1/

Comprehensive chemical analyses will be made on all in-plant flows, mass balances will be secured, and energy requirements estimated. All slurries requiring solid/liquid separation will be bench tested, including where practicable, evaluations with equipment manufacturer's pilot devices. Corrosion/erosion studies will be made with plant materials (solids, liquids, gases and mixtures thereof).

Commercial engineering firms will be canvased for an expression of interest in the design and construction of the 120/TPD (40,000/TPY) demonstration plant (part of the Demonstration, Stage III program). One will be selected from those interested and retained on an advisory capacity to ensure that all data required for the design of a demonstration plant are secured from the plant while it is operating.

1/ The number of days will be specified after the plant residence time is established. Generally, continuous plants operate for between 50 and 100 cycles.

Ongoing Laboratory Program

A laboratory program will be maintained throughout the continuous development stage. The principal activities of the laboratory program are:

1. Support for the plant operation. This includes everything from amenability studies of potential feed coals to rationalizing any process chemistry which might prove troublesome.
2. Formulation of slurries. For both transportation and combustion purposes, it is necessary to understand the optimum means, for a variety of circumstances, of achieving fluidity with Purged Carbons™ product. Coal water, CO_2, pneumatic and butane slurries will all be considered.
3. Process improvement and innovations. During this development phase, the learning curve is steep; generally not only are process refinements set forth, but also breakthroughs can be made, greatly simplifying or improving a circuit or even the entire process.
4. Combustion analysis to optimize environmental and operating conditions. In depth analysis of emissions, slagging characteristics, and equipment wear will help balance cost and purity as well as suggest markets of maximum opportunity.
5. Continuation of organic sulfur removal program. Several approaches are now being pursued which might allow the removal of organic sulfur from the Purged Carbons™ product; these will be continued and accelerated during Phase II.
6. Pursuit of maximum ash removal. Theoretically, all of the ash consistencies of coal can be removed by the effective application of HF and HCl. The target of the Purged Carbons™ program is to produce a coal-based fuel which, on an absolute basis, is cleaner than oil. (.07% ash and less than .2% sulfur levels must generally be attained to meet this objective.

Transportation and Handling

Numerous options among currently practiced methods exist for transporting Purged Carbons™. The selection of the transportation method for a particular case is principally one of economics. They hinge primarily upon:

1. Particle size; three possibilities are:
   a. 1/2-mm by zero, the size produced by the process,
   b. fine powder, less than 200-mesh, the size at which Purged Carbons™ would be used in boilers or heat engines, and

c. pellets, 1/2-inch agglomerates of Purged Carbons™ held together by a binder; pelletized Purged Carbons™ would only be produced if it facilitated transportation in railroad cars or other conveyance.

2. Distance from producer to user or from producer to a delivery point for secondary distribution.

3. The facilities which the user has for storing, handling and using Purged Carbons™; for example, hydraulic pipelining might be preferred if the user was equipped for combusting a slurry.

During this second stage of development (Continuous - Stage II), Integrated Carbons will appraise the relative merits of the numerous transporation methods. The handling, storing and reclaiming of Purged Carbons™ in systems designed for liquids (pipes, pumps, tanks, tankers, etc.) will be the main focus of the work. All systems will be assessed to uncover problems and provide solutions. The economics for various systems also will be developed.

Development or determination of safe methods for handling and storing Purged Carbons™ is an imperative. The possibility for dust explosions and the potential for spontaneous ignition through self-heating will be analyzed and limits established which will define the areas of operation to preclude them. The use of an oxygen depleted gas (flue gas) for handling Purged Carbons™ dry is the likely method for control. Formulation of Purged Carbons™ in a coal water mixture will also be investigated.

Minus 200-mesh (<74-micro meters) and minus 5-microns (<5-micro meters) probably will be the size of Purged Carbons™ when utilized by industry. Integrated Carbons has made initial estimates of the cost of grinding Purged Carbons™ from minus 1/2-mm (its size when discharged from the production plant) to 80% minus 200-mesh, for power plant use and 80% minus 5-microns. These cost studies will be updated and expanded to include different coals and different size consists as dictated by utilization studies.

Utilization

As a substitute for petroleum products, Purged Carbons™, dry and/or in slurries, will be combusted in:

1. Boilers designed for #6 oil

2. Gas turbines

3. Diesels

Purged Carbons™ also has potential in the non-fuel markets including electrode carbon, carbon black, and activated carbon feedstocks. Further, there is some possibility that Purged Carbons™ may be a better bargain than coal in boilers designed for coal due principally to large reductions in maintenance costs and the cost of replacement electricity (generally produced from oil or gas). A complete bus bar comparison of costs will be commissioned.

An active program assessing the suitability of Purged Carbons™ to each of the roles sketched above is contemplated during the second (Continuous - Stage II) development stage. Ton samples of Purged Carbons™ will be produced in a batch plant to supply vendors, development laboratories both government and private, and others interested in the product. These efforts are proliferated because Purged Carbons™ inherits the properties of the organic portion of the parent coal, and for some applications Eastern bituminous feedstocks may be better suited while for others, Western sub-bituminous.

As the program proceeds, Purged Carbons™' samples obtained from the continuous plant will supersede the batch plant samples. Toward the end of this stage of development, utilization tests will be made with Purged Carbons™ produced on a continuous basis.

Economic Evaluation

Project economics are at the core of this development stage (Continuous - Stage II) and the bulk of the program pivots on acquiring whatever data are needed to establish a basis for the economic analyses which will be within ± 20%. Therefore, the personnel responsible for the economic analysis will be intimately involved in planning the continuous plant design and data gathering activities.

In addition to process economics, an outgrowth of the continuous activity, Integrated Carbons will also address the economics of transporting, handling, pulverizing, and utilizing Purged Carbons™.

Project Results

A formal report of the results will be prepared by Integrated Carbons at the end of Stage II of the project. All phases will be integrated into a total assessment of the technology from purchase of the coal through production to utilization of Purged Carbons™.

Proceeding from the second (Continuous - Stage II) to third (Demonstration - Stage III) stage of development will be based upon defined parameters for definition of a viable project -- "technically sound and economically feasible". More specifically, the decision criteria will be resolving of all technical problems and achieving an economic internal rate of return at least 15 points above the prime rate of interest.

Management, Staff and Facilities

The technical program will be directed by Dr. J. Kelly Kindig. He and his staff maintain offices in Denver, Colorado.

The Continuous plant will be built and operated by Hazen Research, Inc. of Golden, Colorado. Hazen Research did the technical work for the Batch - Stage I development. A description of the facilities available at Hazen, along with resumes of key personnel who will be involved with Stage II and economics are presented in Appendix B.

Numerous additional consultants will be utilized in conducting the work, especially in these areas:

1. Commercial application of HF and HCl chemistry.
2. Transportation and handling of Purged Carbons™.
3. Utilization in:
    a. Boilers
    b. Heat engines
    c. Non-fuel uses
4. Environmental and permitting requirements.
5. Selected technical areas, e.g. thermodynamics, materials of construction, alumina industry, etc.
6. Bus bar economic comparisons.

The efficacy of substituting Purged Carbons™ for oil in boilers designed for oil will be assessed in laboratories and bench-scale test boilers owned by one or more of the five major U.S. companies who manufacture the combustion equipment used by utilities and industry. Demonstrating the compatibility of Purged Carbons™ with boilers designed for oil is a priority item and all categories of available resources will be mustered to achieve this goal up to the limit of Purged Carbons™ available for test burns.

It is contemplated additional R&D work will be done at other laboratories such as Southwestern Research, Inc., Battelle Memorial Institute, Colorado School of Mines and others for special analysis and confirmation of results. Also, Integrated Carbons will foster arrangements with selected vendors providing incentives for their developing equipment utilizing Purged Carbons™. Government laboratories (all levels) will be consulted for their interest to participate in fostering Purged Carbons™ utilization.

BUDGET

PURGED CARBONS™ DEVELOPMENT - STAGE II

Item	$000
Technical	
Equipment Costs	$ 1,400
Operating Costs	750
Laboratory Program	1,555
Consultants, Including Engineering Company	435
Transportation	225
Utilization	1,800
	$ 6,165
Operational	
* G&A	835
	$ 7,000

* G&A as shown above is an estimate, and will be billed at actual directly distributable costs, together with an allocation of indirect and non-distributable costs on the basis of generally accepting accounting principles.

EPRI
Electric Power
Research Institute

September 1, 1983

Mr. Roger Sindelar
Subcommittee on Energy and Mineral Resources
Senate Committee on Energy and Natural Resources
SDOB Room 360
Constitution Avenue, NE
Washington, DC 20510

Dear Roger:

Enclosed is testimony by Kurt Yeager for inclusion in the record of the subcommittee's field hearing in Blacksburg, Virginia, August 8, 1983. If you have any questions, please call me at 872-9222. Also, please send a copy of the printed proceedings directly to Kurt at Palo Alto when they are available.

Thank you for your interest in EPRI and for the invitation to participate in this hearing.

Sincerely,

Gene G. Mannella
Deputy Director
Washington Office

GGM/sd

Enclosure: Testimony by Kurt Yeager

1800 Massachusetts Ave., NW Suite 700 Washington DC 20036 Telephone (202) 872-9222
Headquarters 3412 Hillview Avenue Post Office Box 10412 Palo Alto CA 94303 (415) 855-2000

I. INTRODUCTORY STATEMENT

Mr. Chairman, Members of the Subcommittee:

I am Kurt E. Yeager, vice president for Coal Combustion Systems at the Electric Power Research Institute (EPRI). I appreciate this invitation to discuss the clean use of coal. This subject has significant implications for the electric utility industry and, therefore, is of great importance to the Electric Power Research Institute (EPRI).

The EPRI was established by the Electric Utility Industry in 1972 to conduct a broad research and development program for the entire electric utility industry and its rate payers. EPRI's R&D mission is first, to develop new and improved technologies for electric power production, delivery and use and second, to help accelerate their availability thus insuring an adequate supply of economic, reliable and environmentally acceptable electricity.

EPRI is supported by voluntary contributions from investor, government and cooperatively-owned electric utilities across the nation. Over the next five years, EPRI will direct over $500 million to improving coal utilization technology. These efforts will span coal quality control, power plant performance and reliability, fluidized bed combustion, coal conversion and environmental control.

Since its inception, EPRI has worked with the Department of Energy (and its predecessor agencies), the Environmental Protection Agency, and other Federal agencies with energy research and development responsibilities, as well as the private sector to achieve our mutual technical objectives.

II. THE TECHNOLOGICAL CHALLENGE

The past decade brought new challenges that are reshaping the technical approach of the U.S. utility industry to coal utilization. Increasing electrical rates, restrictive environmental controls, uncertainty over petroleum availability, and skyrocketing fuel costs caused the utility industry to consider a variety of new coal-based generating options. These challenges are compounded by restricted capital investment capability, and withdrawal of government funding in technology development.

Coal, our most abundant fossil energy resource, provides over 50 percent of the electricity generated in the United States. Its importance will continue to grow over the remainder of this century, providing at least two-thirds of the nation's energy growth. How the U.S. utility industry and its suppliers respond in this decade will have important consequences for the nation's power generation capability and structure well into the next century.

Technological advances in direct coal utilization which address these challenges are (1) coal quality control, (2) improved flue gas cleanup, and (3) fluidized bed combustion (FBC).

III. COAL QUALITY

Impacts on plant reliability and efficiency caused by declining coal quality have led to a reexamination of the entire power generating system from coal supply to ash disposal. The sensitivity of pulverized coal-fired power plant performance to coal quality has particularly emerged as a major industry concern. As a result, utilities are learning that the cheapest coal does not necessarily produce the lowest cost electricity. Coal cleaning to remove sulfur and ash is, therefore, an increasingly cost-effective option for the utility industry and yet it remains one of the most under developed areas in coal combustion related technology. Its importance is also rapidly increasing as a result of the emphasis on reducing SO_2 emissions from existing power plants using high sulfur coal. Priority objectives for research and development to improve coal cleanability include:

- Improved sampling and analytical procedures to insure confidence in our reserve quantity and quality estimates.

- More efficient and economical fine coal cleaning and recovery techniques.

- More economical chemical cleaning techniques providing thorough sulfur and ash removal.

- Automated cleaning process control and on-line continuous measurement techniques.

- Techniques for cleaning lower rank Western coals.

Federal support for this area has been, and continues to be, minimal. This is particularly unfortunate because the opportunities for technical progress on each of the above objectives is very large relative to the investment required. In addition, such progress can be rapidly translated into substantial improvements in both the quality and quantity of coal utilization.

A principal facility for assessing the effects of coal quality on power plants is the new EPRI sponsored coal cleaning test facility (CCTF) located at the Homer City power station of Pennsylvania Electric Company and New York State Electric and Gas Corporation. Based on commercial scale equipment, the CCTF has a coal handling rate of 20 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can simulate more than 50 commercial cleaning plant designs. Participating utilities and suppliers deliver 1,000 ton coal samples to the CCTF for cleaning characterization. The results provide a reliable estimate of the commercial cleanability potential of the coal, the effect of cleaning on fouling and slagging, as well as verification of cleaning plant design and cost meeting the company's specific needs. Joint programs with the Federal government at this facility would be welcome.

A. Coal Slurries

Continued oil and gas cost escalation, as well as potential supply interruption, are strong incentives for the conversion of oil-fired power plants to coal. EPRI has conducted studies examining the technical and economic considerations in the several options for achieving this conversion. Based on the results, EPRI is conducting research to develop, demonstrate, and commercialize coal-water slurries (CWS) as a cost-effective, oil replacement fuel. This effort builds on the fine coal cleaning technology development underway at the EPRI CCTF.

Coal slurries may substantially lower the cost of coal conversion. The advantage of these slurries over pulverized coal is that they can be transported, stored, and handled with less extensive changes to existing oil-firing facilities. Although encouraging, a number of additional technical and operational issues must be resolved before CWS is available for wide utility use.

These are the focus of EPRI and supplier efforts both here and abroad and should receive aggressive Federal attention which is closely coordinated with the private sector.

- Combustion stability in large-scale boilers must be demonstrated.
- Erosion-resistant burners need development and demonstration.
- Derating as a function of boiler design and operation must be understood.
- Emission control requirements must be defined.
- Commercial slurry product specifications must be defined and vendors must be encouraged to build commercial slurry supply plants ($200 million each).

EPRI projects concentrate on the rapid development and demonstration of CWS from the user perspective. Various coal feedstocks, coal treatment processes, grinding methods, and stabilizing processes are being studied so that selection and use guidelines can be prepared for the broad range of utility conditions. Combustion tests have been performed in small furnaces and development projects are under way to demonstrate stable and reliable combustion in large boilers. Utility scale demonstration of CWS combustion is planned by the utility industry for 1985 if the necessary CWS supply capability is available.

IV. FLUE GAS CLEANUP

In the next twenty years, the utility industry will be faced with maintaining the integrity of power generation and supply with a limited number of new plant additions.

The difficulty of financing new plants, the cancellation and deferment of many nuclear orders, and the uncertain rate of growth of electricity demand are forcing extended use of existing coal-fired generation capacity. This will require continued reliance on flue gas cleanup technology. This importance is further emphasized by the growing issue of acid rain and related emission control requirements for existing plants.

Several years ago, Federal leadership for the development and evaluation of flue gas cleanup systems was transferred from EPA to DOE. This was applauded as a progressive step promoting resolution of reliability, performance and byproduct issues limiting the effectiveness of mandated control technology, particularly flue gas desulfurization. This need is punctuated by the fact that 40 percent of the capital cost of a new coal-fired power plant is typically for compliance with environmental requirements. To date, very few substantive programs have been implemented, although many opportunities for flue gas cleanup technology improvement exist and cosponsored projects with utilities and others have been developed for DOE participation.

The operational limitations associated with the mandated flue gas cleanup technology, together with uncertainty over the future course of environmental regulatory requirements cause the greatest impediment to the increased use of coal.

Recommended areas where concentrated R&D effort is required include:

- Improve the reliability and retrofitability of existing slurry (lime/limestone) scrubbing-systems for sulfur dioxide removal.

- Reduce the quantity and improve the quality of disposable byproduct associated with slurry scrubbing systems.

- Demonstrate regenerable flue gas desulfurization systems which minimize the use of expensive reagents, produce marketable byproducts and rely entirely on coal.

- Develop and demonstrate compact "urban scrubber" flue gas cleanup systems supporting the conversion of existing oil-fired power plants to coal.

- Develop simplified flue gas cleanup systems capable of simultaneous removal of sulfur and nitrogen oxides.

The effectiveness of government funding in this category will depend on a much more aggressive Federal R&D policy which focuses on the key problem areas indicated and commits jointly with the private sector to the major technology projects required for their resolution. By comparison, EPRI alone is investing annually in this area about five times the FY1984 DOE request.

A. Joint Federal/Private Sector Opportunities

Jointly sponsored environmental control technology development and demonstration programs have the greatest potential for significant benefit from Federal environmental R&D. In many cases, even when funding is not a limitation, the technical success and implementation of research results is substantially greater from a joint EPRI/Federal research project than could have been expected if either organization had undertaken the project alone.

The importance of joint EPRI/Federal environmental control research stems from the following advantages of joint programs, relative to research done by a single organization:

- The credibility of the research results is enhanced.
- In many instances, a research program that is only incrementally expanded beyond either organization's own technical objectives can achieve the goals of both organizations at a fraction of the cost of carrying out separate programs.
- First-of-a-kind demonstration of important environmental control technologies can be achieved by the sharing of technical and financial risks among two or more organizations, whereas either alone might not have the financial or technical resources to manage the effort itself.

Past and current joint EPRI/Federal environmental control research programs are summarized in Table 1. This summary serves to illustrate that:

- There has been significant Federal funding in a broad cross-section of EPRI's environmental control technology research.
- Both Federal and EPRI funding have been significant in the joint programs.

Table 1. Joint EPRI/Federal Environmental Control Research

Technology	Years	Federal Agency	Federal $M	EPRI $M	EPRI Role(1)	Objective/Results
Combustion control	74-75	EPA	0.3	0.2	MP	Field evaluation of combustion modifications to reduce NOx and other emissions
Combustion control	74-75	EPA	0.1	0.2	MP	Combustion and emission characteristics of low Btu gas
Precipitators	75-76	EPA	0.3	0.5	MP	Define rapping and reentrainment mechanisms, effect of gas conditioning on ash resistivity
Precipitators	76-83	EPA	0.1(2)	2.1	PS	Define mechanisms of flue gas conditioning for ESP per performance improvement
Precipitators	79-81	TVA	1.2	0.5	MP	Full-scale high intensity ionizer evaluation
Precipitators	80-83	EPA	0.1	0.3	PS	Pulsed power supply tests
Particulate control	84+	EPA	0.1	0.1	MP	Joint particulates control symposia
SO_2 scrubbers	75-78	ERDA,EPA, TVA	4.4	0.6	MP	Pilot scale scrubber process developments
SO_2 scrubbers	77-85	DOE	1.0(2)	3.9	PS	Scrubber chemistry development and model
SO_2 scrubbers	77-80	TVA	1.4	4.4	MP	Prototype scrubber evaluations
SO_2 scrubbers	78-84	EPA	0.5	0.4	MP	Design guidelines, scrubber data base
SO_2 scrubbers	78-85	EPA	9.3	53.1(3)	MP	Sulfur recovery SO_2 scrubbing demonstration (Aqueous Carbonate Process)
SO_2 scrubbers	80-84	EPA	0.3	3.4	MP	Spray-dry SO_2 scrubber evaluation
SO_2 scrubbers	82,83+	EPA	0.1	0.1	MP	Joint SO_2 control symposia
NOx removal	76-78	TVA	0.1	0.4	PS	Evaluation of postcombustion NOx removal
NOx control	78-82+	EPA	0.2	0.2	MP	Joint NOx control symposia
Cooling water intake	78-82	EPA	0.5	0.8(3)	MP	Porous dike intake structure demonstration
Cooling system	78-80	EPA, ERDA	0.8	0.2	MP	Cooling system design to minimize entrainment mortality
Cooling towers	78-79	EPA	0.4	0.2	MP	Cooling tower blowdown evaporator/crystallizer tests
Cooling towers	81-85	TVA	0.2	2.6(3)	PS	Cooling tower performance pilot tests
Wet/dry cooling	75-79	ERDA, EPA	0.2	0.1	MP	Wet/dry cooling performance test and model
Dry cooling tower	76-85	DOE,EPA	3.0(2)	15.6(3)	PS	Ammonia dry cooling demonstration
Ash and sludge disposal	78-83	DOE,EPA	1.5	1.3(3)	MP	Ash-and-sludge artificial reef demonstration
Ash utilization	78-83	DOE,ORNL	0.2	0.4	MP	Acid leach alumina recovery development
	74-85		25.6	91.6(3)		

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(1) PS = Principal Sponsor, MP = Major Participant
(2) Federal agency planned stronger role, but budgets were cut
(3) Includes utility and other private sector contributions: total EPRI funding $46.3 M out of $91.6 M.

Potentially fruitful research areas for future joint efforts include the following:

- Full-scale demonstration of SO2 control by injection of dry sorbent (limestone) into a utility boiler

- Low NOx combustor development and full-scale demonstration

- Electrostatic precipitation pilot testing and development at existing (unused) EPA facilities at Public Service of Colorado Valmont station and TVA Bull Run station.

- Aqueous discharge sampling and analysis protocol development

- Resource recovery/utilization of large-volume combustion byproducts, e.g. fly ash

- Low-volume wastes fixation technology demonstration

In addition, an accelerated five year national program designed to provide answers by 1988 to the key questions relating to the acid rain issue has been recently submitted to EPA. The program represents a comprehensive extension of activities already underway at EPRI and within the Federal agencies and incorporates much of the Federal acid rain research plan prepared by the Interagency Acid Rain Task Force.

We estimate the total cost of this accelerated R&D effort to be about $900 million over the five year period. EPRI presently plans to commit $175 million to this overall program. We expect utilities to contribute significantly to the emission control work and government to the ecological effects, atmospheric science and resource management components. EPRI will spend an additional $300 million on science and technology related to coal-fired power plant environmental issues and advanced coal technology, including fluidized bed combustion and coal gasification, during this same period.

B. Integrated Environmental Control

Today, environmental regulatory requirements on coal-fired plants involve continuous control of air, water, solid waste, and thermal discharges. This has become a major cost factor in construction and operation, typically 30 to 40 percent of a coal plant's investment cost. The high-cost, poor reliability, and reduced operational flexibility resulting from the add-on, piecemeal response to these rapidly changing environmental control requirements are changing the historical approach of user, designer, and supplier.

Environmental control in the 1980s has become as much an integral part of the coal-fired power plant system as the boiler or turbine. A design strategy which pursues a more systematic approach to control of all effluent streams may offer capital savings of $100 per kilowatt, increase plant availability by 5 percent, and improve heat rate by up to 500 kilojoules per kilowatt-hour. These savings occur less from new technology than from assigning single point responsibility for environmental control system design and elevating its engineering priority to a level equivalent with its economic importance.

EPRI's integrated emission control pilot plant (IECPP) at the Arapahoe power station of Public Service Company of Colorado in Denver has the flexibility to test a very wide range of possible equipment configurations. Initially focusing on air, water, and solid waste control technologies, the pilot scale program represents a cost-effective means to obtain critical design and operation information. The overall goal is to produce engineering design guidelines for the selection, configuration, and operation of integrated environmental control equipment under the operating conditions a typical utility might encounter. Emphasis is on the emissions control capability and on the interface among the various components and the power plant to minimize operating, maintenance, and cost requirements.

The IECPP is the first coal-fired pilot system in the United States for investigating different integrated emission control systems and for providing environmental management services to the utility industry. The equipment options provide the unique advantage of sophisticated research flexibility at a size representative of large, commercial installations.

V. FLUIDIZED BED COMBUSTION

The electric utility industry also is aggressively evaluating and developing technologies which may ultimately provide less costly and more reliable operation than current pulverized coal systems. These options are intended to carry utility coal utilization beyond the limits inherent in pulverized coal technology. The most important factor in commercial acceptance will be their demonstrated capability to be at least as reliable as pulverized coal-fired power plants. Accordingly, priority must be placed on reliability. This requires the construction and operation of large-scale, engineering prototype or pioneer plants over a range of designs and fuels at operating conditions which are representative of the using utility industry.

EPRI and the utility industry are accelerating the development and application of fluidized bed combustion as a further evolutionary improvement in coal utilization to meet the expanding needs for coal-fired power generation. The improvements which excite this utility interest include reduced sensitivity to fuel quality, thus permitting the use of a much broader fuel supply, from anthracite to municipal refuse, without suffering large losses in efficiency and reliability in a single boiler design. Less cost sensitivity to unit size in a period when load growth and siting restrictions may favor smaller FBC boilers rather than larger pulverized coal furnaces.

A third primary advantage of FBC that may lead to the displacement of pulverized coal boilers is environmental performance. Our experiments with fluidized combustion of coal confirm that it is possible to control sulfur and nitrogen oxides economically without parasitic, postcombustion cleanup devices.

A. Atmospheric Fluidized Bed Combustion

Termination of DOE support for AFB technology development is occurring at a time when the technology is achieving a commercial foothold for industrial application. The DOE program has been instrumental in achieving this demonstrated capability of AFB to reliably produce steam from coal for small industrial and space heating applications. The program has included installation of several industrial demonstrations and is an example of the success that can be achieved through a well planned and consistent government research, development and demonstration program, conducted in a manner complementing private sector capabilities and objectives.

Development of AFB has successfully progressed from the process confirmation state to engineering prototype, making commercial utility scale application practical this decade if the follow-on demonstration plant can be constructed. TVA has taken the lead, with EPRI support, in implementing a 20 MW engineering prototype which has been operating successfully for over one year. This facility has only been possible with major Federal R&D support through TVA.

The results provide the technical basis for 100-200 MW commercial scale demonstrations by the utility industry operational this decade. In support of this goal, EPRI has recently authorized $75 million for participation in a $220 million AFB demonstration cosponsored by TVA, Duke Power and the State of Kentucky. This was one of several utility AFB demonstration proposals submitted in response to an EPRI solicitation. Other such projects which we hope will proceed were submitted by Northern States Power, Colorado Ute, Puget Sound Power and Light, and Cleveland Electric Illuminating Company. In each case the host utility proposed to fund the major portion of the cost of the demonstration, with EPRI and the boiler manufacturers sharing the risk costs with the utility.

In addition, I believe this commitment will help maintain the technical and commercial leadership of our domestic boiler manufacturers since the characteristics that make AFB attractive domestically have equal or greater merit in the international market. It should be recognized, however, that such a costly project conducted in the private sector must satisfy additional, nontechnical constraints not generally present in Federally funded demonstrations. The facility must produce an immediate revenue for the participants. In the case of the utility industry, this means the demonstration must be a commercial power producing facility capable of reliable, extended operation, at costs less than existing technology.

Providing the necessary confidence in such a step puts a major burden on the technology development effort. If the private sector is to be responsible, then the demonstration becomes less the last step in the development process than an assured commercial venture. The continuity and success of the combined Federal/private development effort to date may make this pioneer demonstration step for AFB commercially viable primarily through private support. This, however, is likely to be the exception rather than the rule unless Federal support for coal combustion R&D, including critical pilot and demonstration plants, is maintained at a substantially greater level than currently authorized.

I am encouraged that the on-going Congressional review and mark-up of the requested DOE appropriation indicates possibility of augmented funding for the TVA/EPRI/Duke Power/ Kentucky demonstration of AFB. If sustained, this support will be instrumental to completing the development and commercialization of an important utility coal technology whose success to date has resulted from the cooperative actions of government with the private sector.

B. Pressurized Fluid Bed Combustion

The new and dynamic utility climate also influences pressurized fluid bed combustion (PFBC) development goals. The influence arises from the trend toward smaller unit size and growing utility interest in uprating the capacity of existing units to bring capacity on line at the lowest investment cost. As a result, development emphasis is being placed on turbocharged boilers which can provide shop fabricated, barge transportable, steam [4]generation modules. These can be rapidly field-erected to provide the desired uprating in unit sizes of 150 to 250 megawatts. This approach will use coal to replace and increase the capacity of existing plants while minimizing space and environmental control requirements. It also indicates the lowest capital cost and busbar energy cost of any coal option, even in relatively small unit capacities.

The primary physical difference between the turbo-charged boiler and the PFBC-combined cycle that has been previously emphasized is the reduction in gas turbine operating temperature. This substantially reduces the development risk and cost, and improves the reliability of the boiler system.

Efforts are now being initiated by EPRI to design engineering prototypes of the turbocharged boiler based on results from operational pilot plants. This approach should permit commercial prototypes to be operational this decade, thus yielding important financial advantages to utilities during the current period of low-load growth and high-construction costs.

Unfortunately, the impact of DOE funding reduction is nowhere more immediately evident than in the PFB development program. Major progress has been made over the past several years in converting this technology from an engineering curiosity to an important electric power producing technology having the lowest busbar energy cost potential of any nearterm coal utilization option. The effective cancellation of DOE support on the brink of successful proof of commercial viability is indeed "seizing defeat from the jaws of victory." This is particularly unfortunate since PFB is one clear example where DOE efforts have been instrumental in developing an important but high risk new coal utilization technology nearly to the point where transfer for private sector commercialization is feasible.

Although development results have been encouraging, much additional progress must be made before confidence is sufficient to warrant commercial application. The Curtiss-Wright and International Energy Agency (IEA) Grimethorpe pilot PFB facilities are the key instruments for achieving this confidence but are threatened with termination by withdrawal of DOE support. In considering the merits of these facilities, it is important to recognize that they are technically complementary and an "either/or" funding mentality is counterproductive.

The major limiting factor restricting commercial realization of this capability is confidence in the design base for the PFB boiler. Although many of the technical issues affecting the gas turbine and balance of plant have been reduced or eliminated by the turbocharged boiler approach, the boiler remains the critical pacing development issue. Under these conditions I believe no single issue is more critical to the commercial success of PFB than continued operation of Grimethorpe. Grimethorpe is the only operational PFB facility in the world which has the technical capability and size to adequately address the pacing development issues of PFB. In addition, it is supported by the largest concentration of PFB experience in the world. Its results are nonproprietary and are available to participants in each supporting nation. In short, its capabilities are irreplaceable and represent one of the most valuable applications of Federal energy R&D funding.

At the present time Grimethorpe is concentrating on resolution of in-bed heat transfer tube bank erosion. This is obviously critical to further PFB system development. Elimination of U.S. support in 1983 will cut short this effort and prevent the long-term testing necessary to insure confidence in the design base. Further PFB development requirements which need to be addressed at Grimethorpe include process operability and control, coal and ash handling, and confirmation of gas cleanup system reliability and performance.

I, therefore, strongly recommend that U.S. support a streamlined, reduced cost Grimethorpe project to be continued through 1985. Failure to do so will cut us off from our most valuable source of development capability and stall the private sector's efforts to achieve the technical and commercial advantages of PFB. EPRI supports the efforts of the Administration and the Congress to reduce Federal budget deficits. It is nevertheless incumbent on EPRI to identify those areas of energy R/D that require additional support. This is done in the context of advocating higher priority within the budget process as a whole, rather than increased appropriations.

It is unrealistic to presume that the private sector can maintain the Grimethorpe and Curtiss-Wright facilities alone given the as yet relatively unproven status of PFB technology. We have suggested a joint effort with DOE to posture a comprehensive Federal/private sector R&D plan that best uses the limited Federal and private resources available to address the key question facing commercial acceptance of PFB technology. EPRI and interested manufacturers, including General Electric and Babcock & Wilcox, stand ready to work with DOE in addressing these difficulties.

Unfortunately, lacking a further Federal commitment of about $6 million per year in 1984 and 1985, it appears that these promising facilities will be terminated before beginnning to recover the major Federal investment on their construction. On the other hand, if the Grimethorpe and Curtiss-Wright programs are successfully completed, EPRI hopes to implement a commercial PFB prototype with the utility industry. Probable absence of government funding increases the necessity that such an installation provide actual electric generating capacity to interest the necessary private sector funding. Although the EPRI plan contains support for such a project, its full funding mechanism is not yet evident. I emphasize, however, that such a commercial demonstration can only be implemented if the Grimethorpe results indicate, to users satisfaction, the Grimethorpe results indicate, to users satisfaction, confidence in the reliability and operability of PFB power plants. This will require restoration of Federal /participation in PFB.

VI. CONCLUSIONS

1. Coal now provides over 50% of the electricity generated in the United States. Its importance will continue to grow over the remainder of this century, providing about two thirds of the nation's energy growth over this period. The emphasis in U.S. coal technology development is on near-term resolution of the reliability, cost and environmental issues limiting domestic coal utilization, as well as the demands of the increasing important world market. The focus should be, therefore, on improvements in coal quality control, flue gas clean-up and fluidized bed combustion of coal.

2. The actions of the Federal government in direct support of energy related research and development and in the form of incentives have a profound effect on the utility industry's ability to develop and use new coal utilization technology. As such, they have major impact on the EPRI program. Federal R&D policy with respect to the utility industry needs to consider the

underlying circumstances affecting the industry and the importance of electric energy to the nation's energy, security and economic needs. Federal participation in selected coal combustion and other programs will be necessary if successful transfer to the private sector is to occur. This is particularly important for pilot and demonstration projects as well as long-term research.

3. Research and development groups are fragile entities that once disbanded, cannot be restored. I would, therefore, urge that any changes in Federal energy R&D policy be made gradually so that the system can adjust with minimal damage. Unfortunately, the reductions implemented and proposed in recent Federal budgets have occurred so suddenly that opportunity for coordination to reduce the shock has been minimal in most programs.

4. Clean coal related technology where this continued Federal R&D collaboration is most critical must start with Fluidized Bed Combustion (FBC). Specifically, the proposed termination of the Grimethorpe pilot facility may stall the promising pressurized FBC technology initiative underway in the private sector to provide a modular, low cost, clean and more rapidly built coal fired power generating capability this decade.

5. Collaboration between government and the private sector in the pioneer FBC and coal conversion plants being implemented by the utility industry is also essential to the rapid commercial availability of these technologies. Of particular importance is the TVA/EPRI/Duke Power/State of Kentucky Atmospheric FBC Demonstration.

6. Greater Federal emphasis should also be placed on resolving the technical issues limiting the effectiveness of mandated environmental control technology. These limitations, combined with uncertainty over the future course of regulatory requirements, pose one of the greatest impediments to increased coal use. This is underscored by the uncertainties and potential financial demands on the utility industry and its rate payers by the acid rain issue. The utility industry, through EPRI, plans to commit an additional $175 million in R&D on this issue alone over the next five years.

7. Given the difficulties presently being experienced with the nuclear power option, high sulfur coal looms even more essential in the future. We believe flue gas scrubbers represent a band-aid approach, often creating as many problems as they solve, and should be

rapidly as possible. Adding scrubbers to older-plants is uneconomic and will delay use of improved coal utilization options such as FBC.

8. The alternative fuel utilization program co-sponsored by DOE is essential, particularly in the area of coal-water mixtures. This work, together with the efforts sponsored by EPRI and others in the private sector, will provide the necessary technical confidence for commercialization of this important oil replacement option. Development of techniques to produce stable, pumpable mixtures of coal and water offer the possibility of a substantial fuel cost saving that could justify conversion of oil-design boilers to coal and provide valuable insurance against oil supply interruption.

9. Longer range, higher risk coal programs which should also receive higher priority for continued Federal R&D support include materials research, direct coal utilization, and coal preparation and analysis. Of particular importance in the latter category is greater confidence in our coal reserve quality and quantity estimates and improved quality improvement and control techniques for our lower rank coals.

The reduction in Federal emphasis on direct coal utilization is also of major concern. This reduction will have a major impact on the national technology base necessary to maintain our competitiveness in both domestic and international markets.

10. There is no shortage of opportunities to improve the efficiency, reliability and environmental performance of coal combustion. The successful achievement of the objectives laid out in this testimony requires, however, a more constructive and coordinated partnership between government and the private sector. This encompasses the planning and implementation of R&D as well as the commercial transfer of results.

11. The rate of commercialization and use of improved technology also depends on the development of regulatory and economic incentives which encourage introduction of innovative technology. Too often our dependence on the adversarial approach to resolution makes the conflicts restricting coal use more severe and disruptive than necessary and restricts the introduction of technological improvement.

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COAL SLURRY PIPELINE TECHNOLOGY AND SOME OF ITS IMPLICATIONS IN VIRGINIA

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INTRODUCTION

In view of the renewed emphasis on the production, use and export of high-quality but currently troubled Virginia coal, slurry pipelines are now more than ever recognized as a viable alternative mode of long-distance transportation. Since 1957, over twenty long-distance slurry pipelines have been designed and constructed all over the world transporting such minerals as iron, copper, nickel, limestone, phosphate and coal, among others. They are technologically proven and have extremely high operational efficiency, as examplified by the 273-mile, 18-inch, 5.0-million ton per year Black Mesa coal slurry pipeline, which has had a virtually trouble-free operation with over 99 percent efficiency since 1970.

The major economic advantage of the long-distance, large-throughput slurry pipelines is that they are highly capital intensive, with about 70 percent of their cost being fixed, and thus insensitive to inflation. Their interaction with the environment is quite negligible as compared to other modes of bulk material transportation. The effluent water from the dewatering facilities can be upgraded quite routinely and at no substantial costs so as to meet the local, State and Federal standards. In fact, recent investigations at the ETSI Coal Evaluation Plant in Arkansas have clearly demonstrated, that the effluent water has even fewer total suspended solids than the original stream water of Arkansas river.

In this presentation, after a brief review of the current state of slurry pipeline technology, the preliminary feasibility characteristics are summarized for conceivable coal slurry pipelines in Virginia, along with some of the probable implications of the technological, economical and legislative developments.

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CURRENT STATE OF COAL SLURRY PIPELINE TECHNOLOGY

A cross-country type coal slurry pipeline consists mainly of three basic system components; namely, (a) the slurry preparation facility at the point of origin, (b) the pipeline and pumping stations, and (c) the coal recovery or dewatering facility at the receiving terminal. Today, almost an "off-the-shelf" kind of established technology is available on the various technical design, construction and operation characteristics of each of these system components. In fact, it has been frequently stated, that the overall technology of slurry pipeline transportation will not change much in the near future, at least for the "conventional" slurries. Increasing the capacities and efficiencies of such equipment as pumps and valves, particularly the operational life of their moving parts, improving instrumentation and operational control, and hydraulic transport of coarse coal and dense-phase slurries of fine coal, widely referred to as the coal-water mixture fuels, are areas in which new technologies and methodologies are under continuing investigation. The prime motivation in these investigations is, however, predominantly economical rather than technical.

Although each slurry pipeline project is quite unique, the main principles and methods of approach remain invariably the same. Intensive research, design and further development activities have always been successful in answering the new questions that arise with every new project. It is also due to this success, that scientists and engineers are now ever more ambitiously involved in research and development extended to integrated total transport systems involving conventional as well as nonconventional slurry pipelines.

Two overseas coal export projects investigated by the Boeing Group for the U.S. Marine Administration have clearly shown, that enormous economic advantage is provided when slurry pipelines form an integral part of the total transportation system. In one of these projects, a 300-mile slurry pipeline originating in Waynesboro in southwestern Pennsylvania would deliver up to 10 million tons of steam coal to an offshore ship loading terminal near Dover in Delaware, at about 50 percent lower costs than an existing railroad system, thus reducing the transportation cost of delivered coal in Europe from about $30 per ton down to about $21 per ton. Canada, Australia, Italy, France, Netherlands, Japan and South Africa are also investigating similar projects very seriously. It is strongly argued, that as soon as the production, overseas shipment and demand scenarios are properly matched, these projects will become a reality, and slurry pipelines will undoubtedly offer one of the most feasible alternative for these integrated total transportation systems.

Regarding the nonconventional slurry concept, coarse coal slurry pipelines have emerged as attractive alternatives for vertical haulage of deep mined coal to the surface, for pick-up spurs in gathering systems, as well as for offshore loading/unloading slurry systems. It is strongly suggested that coarse coal slurry pipelines will gradually replace the conventional nonslurry transportation systems in mine operations from safety, efficiency and economic points of view. A prime example, in this respect, is the successful operation of such a system constructed by the Consolidation Coal Company at its Loveridge Mine in West Virginia, which transports the mined coal to the surface through a vertical lift of almost 900 feet. It is reported, that due to the confirmed safety, operational and economical advantages, such systems are now seriously considered appropriate for larger scale operations. A similar operation has also been in service for some time at the Hansa Mine in the Federal Republic of Germany.

Another application of coarse coal slurry pipelines is in relation to a coal export facility, in which case, a pipeline would form the link between the railroad terminal and the port, whether it is onshore or offshore. The Stapleton project of the New York City Port Authority is a prime example, in this respect. An important component of the project is a 30-inch diameter coarse coal slurry pipeline to convey 2-inch top size coal from the railroad terminal to the port at the rate of 20 million tons per year. Such a system was found to be the optimum alternative, despite the fact that it includes a return pipe for recycling water. There are a number of similar projects with similar integrated systems, already built or being considered around the world for both onshore and offshore terminal operations. In fact, a single point mooring buoy system in New Zealand has been in operation since 1971, and the Waipipi iron sands have been transported from the onshore port to large deep-water ships by a submarine pipeline.

Much finer but cleaner coal mixed with water in as high concentrations as 75 percent by weight, known as the coal/water mixture fuels, have been under extensive investigation by quite a few number of diversified organizations, with high hopes and strong evidence that these fuels will soon take the place of conventional fuel oil in utility power plants. In addition to the development of such mixtures with favorable rheological and combustion characteristics, minimization of the cost of the produced mixture fuel, and perhaps more importantly, the cost of its transportation to the utility power plants, are among the main areas of research. In fact, since the cost of transportation of the product to the utilities can be a major portion of the total cost, it seems imperative for an economical application of these fuels to consider a multi-mode, integrated transportation system involving the most economical combinations of any or all of the possible transportation modes. Depending upon the specific circumstances, these alternative transportation modes may consist of the conventional bulk transportation systems, such as railroads, trucks and barges, in both dry-bulk and tanker forms, or conventional coal slurry pipelines, and finally coarse or fine coal slurry pipelines. Therefore, it is strongly argued, that a careful economic evaluation of such multi-mode, integrated transportation system alternatives is prerequisite to even the decisions pertaining to the most economical location of the coal-water mixture fuel preparation plants.

PRELIMINARY FEASIBILITY OF COAL SLURRY PIPELINES IN VIRGINIA

In view of the favorable characteristics of slurry pipelines and the great deal of general interest in improving the overall situation of coal movement in Virginia, determination of the overall technical, environmental and economic feasibility of coal slurry pipelines in Virginia was considered highly appropriate and indeed essential. In a preliminary feasibility study undertaken at Virginia Polytechnic Institute and State University (Virginia Tech), basic though preliminary data were produced for eight conceivable alternative pipeline routes between southwestern Virginia and the tidewater area, to transport up to 25 million tons of coal per year. The investigation was partially supported by an unrestricted grant provided by Virginia Electric and Power Company (VEPCO) through the Virginia Center for Coal and Energy Research. The optimum pipeline characteristics determined were associated with pipe sizes, the number and locations of the pumping stations, slurry preparation, pumping, dewatering and operational equipment, energy and water requirements, as well as the capital and operating costs of the various system components. Grundy up in the north, Big Stone Gap in the south and Pound in the middle portion of southwestern Virginia's coal region were considered as typical candidate locations for the beginning of the pipeline, which could easily be linked to various regional mines through an appropriate gathering system consisting of trucks, railroads or short-distance coarse-coal slurry pipelines. The main terminal point considered at that stage was Portsmouth, in regard to both power generation and export operations. There are also several power plants along these alternative routes which may be considered as take-off or terminal points of interest. Thus, the general aim of the study was to determine the overall technical, environmental and economic features of a slurry pipeline to span the entire Commonwealth, from which relevant data for various other possible alternative scenarios could also be derived with minor additional analysis.

Regional Characteristics

The general topographical features of the region indicate the existence of basically two alternative routes, which actually amount to eight alternatives for the various possible combinations involving one terminal (Portsmouth) and three origination points (Grundy, Big Stone Gap and Pound). The total pipeline lengths vary between 380 and 470 miles and the first 150 to 250 miles involve relatively rougher terrain. Pipeline slopes averaged over 5-mile intervals remain mostly below 2 percent, reaching a maximum of only 4 percent. The actual pipeline will probably encounter somewhat larger local slopes. However, in view of the generally accepted limiting value of 16 percent for upgrade and downgrade slopes to avoid slurry clogging, as well as considering such problems as river and highway crossings, the topographic conditions are not expected to present any extraordinary engineering, construction or operation-related difficulties.

Computer Model of Hydraulic and Economic Optimization

The optimum system characteristics were determined with the use of a computer program developed specifically for this purpose. For each given annual throughput of coal and along each alternative route, the program first makes all the necessary calculations for the slurry flow, pipe and pumping station-related hydraulic characteristics, and subsequently calculates the capital and operating costs of the various system components. Finally, an overall cost evaluation is made to arrive at the solutions yielding the lowest transportation cost per ton of coal for each of the specified alternative scenarios, and the results are presented using both tabular and graphical formats.

Hydraulic Transport and Cost Characteristics

Before the design of the system is finalized, the actual transport characteristics must be determined by means of full-scale pilot-pipeline experiments using the particular types of coal subject to transportation. At this state, however, it was assumed that the slurry preparation facility will produce essentially the specified size, prepared as a coal slurry, for which such experimental data are available and were utilized as input to the computer model employed in this study.

Due to the lack of a financial scenario that can directly be assumed to apply to a prospective coal slurry pipeline in Virginia, a rather simplistic economic model was employed to generate a data base for a preliminary economic comparison of the various alternatives studied. Present worths and annuities for the total project costs were evaluated using a range of fixed annual interest rates varying between 10 and 30 percent applied throughout the project life taken as 30 years. Thus, the spectrum of data produced for each alternative route and annual throughput should prove useful for reference purposes in conjunction with any future financial scenario. Transportation costs ($/ton) and unit transportation costs (c/ton/mile) were calculated using total annual expenses including the cost of capital.

The cost results obtained for a specific annual throughput exhibited only slight variations between different route alternatives as well as different number of pumping stations. This is probably a significant positive feature of coal slurry pipelines in Virginia, since it implies that a conceivable range of design variations that may be applied in the future will apparently not alter the overall optimum design characteristics to any significant degree.

TECHNOLOGICAL AND ENVIRONMENTAL CONSIDERATIONS

As it was stated earlier, "the overall technology of conventional coal slurry pipeline transportation is at a very satisfactory level, and will not change much in the future." With the established technology of the "technically 99 percent efficient" Black Mesa pipeline and further improvements achieved for the Energy Transportation Systems, Inc. (ETSI) pipeline, design, construction and operation of coal slurry pipelines are now virtually free from any major problems. Furthermore, topographical and other relevant features such as special crossings have also appeared to pose no extraordinary problems that cannot be rather routinely handled with today's "off-the-shelf" technology. These statements would directly apply to the conceived coal slurry pipelines in Virginia.

From an environmental impact point of view, on the other hand, the following remarks can be made to briefly illustrate the overall superiority of coal slurry pipelines over the railroads, in particular. Dust, noise, diesel fumes, frequent delays due to traffic hazards involving other vehicles, animals, pedestrians or strikes, antiaesthetics of a mile-long train of coal hoppers, and blocking of other surface traffic, are all elements of immediate and long-run environmental impact for conventional and unit-train systems. The best computerized railroad operations system available today still permits collision between trains themselves as well as other vehicles and objects. The not-so-frequent, "unknown cause" derailments are always newsworthy, and the loss of human life is always reported. But what is frequently lost in the news release is the fact that roadways may be tied up for days, tons of coal or other goods including hazardous material may be scattered around the neighborhood, diesel fuel may be spilled devestating the track-side vegetation, ensuing fires, and often widespread and lingering air and other kinds of pollution may follow quite ordinarily after each derailment.

Insurance companies will testify, on the other hand, that pipelines have an enviable safety record. Coal slurry pipelines are often regarded as in their infancy, but the well-established Black Mesa line has a record of 99 percent successful operation. Coal and other slurry pipelines are dustless and noiseless for all intents and purposes, practically independent of vagaries of weather, traffic and priorities of other shippers. The extremely infrequent occurrence of line plugs may require some temporary shut down of the slurry line. But, even if the pipeline must be uncovered and cut to remove the plug, this is quite miniscule in time and cost when compared to a train wreck. Coal mines and slurry pipelines are subjected to repeated analyses by environmental teams. But according to the records available, no one has yet ordered an environmental impact statement for the assessment of exponential increases in rail traffic in rural and urban areas, which together with the increased highway tarffic, results in an inevitable compromise of safety and conveyance in the area of a passing train.

One of the more frequently discussed environmental impacts of coal slurry pipelines is concerned with the quality of water received at the end of the pipeline, and the technical as well as economic feasibility of its treatment for possible reuse or discharge to surface water courses in order to meet the federal and local effluent requirements. Experience from the Black Mesa operations, as well as more recent developments associated with the ETSI pipeline, clearly depict, that, quite contrary to the frequent arguments of many, environmentally-important heavy metals are not leached at detectable amounts into the water, despite the significant levels they may have in coal. Even more interestingly, because of the rather good sorption qualities of coal for organic compounds and heavy metals, it has been suggested that serious consideration should be given to the use of coal slurries for water purification. In fact, recent investigations at the ETSI Coal Evaluation Plant in Arkansas have demonstrated, that the effluent water from the pipeline dewatering facility has even fewer total suspended solids than the original stream water of Arkansas River. Consequently, the so-called "water quality problems" are actually not severe by any means and can be resolved to any desired degree without involving substantial costs, using the remedial measures and techniques that are available today for upgrading the slurry wastewater quality for reuse as process water or to allow discharge to surface water courses.

ENERGY EFFICIENCY CONSIDERATIONS

Based on the detailed results obtained concerning the predicted energy consumption of the conceived coal slurry pipelines in Virginia, it can be briefly remarked, that while the quantitative characteristics of coal slurry pipelines vary considerably with the length of the pipeline and the annual amount of coal transported, the general trends obtained from numerous specific and broad-based investigations appear to favor slurry pipelines at least for the relatively long-distance and large-throughput systems. For example, the famed ETSI pipeline will provide a 96 percent energy efficiency, since it is predicted to consume about 650,000 Btu/ton of coal delivered, while transporting a coal valued at about 24 million Btu/ton. Railroads, on the other hand, would provide about the same energy efficiency, but since they utilize diesel fuel, this efficiency would drop to 92 percent as equivalent of coal-based energy. Therefore, it can be concluded that while the energy intensities in terms of Btu/ton-mile are quite comparable, with perhaps a slight advantage for the railroads, there is a strong counter effect in view of the at least strategically valuable diesel fuel that railroads expend.

WATER SUPPLY AND WATER RIGHTS CONSIDERATIONS

On another frequently debated topic, despite the frequently stated "critical shortage of water supply in the region", a preliminary examination of the basic stream flow characteristics of the Grundy-Pound-Big Stone Gap region in southwest Virginia has produced rather optimistic results. It appears that even the rather small-size streams that exhibit relatively variable flow characteristics during the year would be able to satisfy the demand of a coal slurry pipeline with proper management and without incurring any conceivable damage to the local environment. This is supported by the fact that although the streams in the region do have low-flow periods, they also have sufficiently high mean-annual flows as well as often extremely high flows which have produced many severe floods in the region. For example, the following typical values can be mentioned for Levisa and Russell Forks. As indicated by the stream flow, records for Levisa Fork at Big Rock about 10 miles downstream from Grundy, the average precipitation is about 18 inches, the annual mean stream flow about 400 cubic feet per second (cfs), while floods as high as 56,000 cfs and a week-long minimum flow of 5.0 cfs have also been recorded. SImilarly, the records for Russell Fork at Haysi indicate that annual mean flow is about 330 cfs while the maximum and minimum flows are about 59,000 cfs and 0.2 cfs, respectively. The other streams in the region also exhibit similar characteristics of highly variable streamflows. Coal slurry pipelines to transport up to 25 million tons of coal per year, on the other hand, would require constant rates of up to about 30 cfs. It can easily be concluded, therefore, that first, the average amount of water demanded by the pipelines is only a small fraction of the mean flows of the regional streams, and second, it is an ideal case that can be solved with proper management, such as by way of seasonal storage.

In a recent master's thesis study conducted at Virginia Tech for a preliminary assessment of the impoundment requirements, the emphasis was placed upon the offstream-type, man-made reservoirs which are dedicated to the use of the coal slurry pipeline only. Conventional reservoirs would also serve to directly regulate the stream during both low-flow and flood periods. The offstream type reservoirs, on the other hand, were considered in view of their several apparent advantages, such as, minimum interaction with the normal environment of the stream, thus fewer environmental restrictions; smaller reservoir volumes required to satisfy the pipeline requirements; and that only the pipeline management would probably be responsible for their operation.

The calculations, particularly for the offstream impoundments, were made according to several different scenarios conceived for application to diversion from the stream. Each scenario assumes a series of different diversion rates (QP) from the stream when the stream discharge (QS) is within different ranges of fractional values with reference to the mean discharge (QM) of the stream. For example, according to one of these scenarios, when the QS is less than 25 percent of the QM, no diversion is allowed, i.e., QP=0. When QS is within 25 to 50% of QM, 5% of the current QS is allowed for diversion, to either fill the offstream reservoir or to feed the pipeline directly or any combination thereof, i.e., QP=5% of QS. Similarly, QP=10% of QS when QS is within 50 to 100% of the mean stream flow, and QP=15% of QS when QS is greater than QM. Also considered as constraints in these calculations are a series of maximum diversion rates allowed from the stream at any time, such as 5, 10, 15, and 20 times the continuous demand of the pipeline. This implies that for a 10.0-mty pipeline, for example, the maximum diversion rates allowed in the calculations would be 60 cfs, 120 cfs, 180 cfs and 240 cfs, based on the continuous demand of the pipeline. Each of these constraints would actually determine the capacity of the diversion or intake structure as well as of the conveyance line between the intake and the reservoir, as the latter may not be located directly next to the diversion intake. The preliminary results indicate that when the maximum diversion rate allowed is 120 cfs (= 77.6 million gallons per day) and, for the scenario prescribed herein, a 10-mty pipeline will require an offstream reservoir of only about 4,600 acre-feet, which is approximately half the size of the nearby Pound River Lake.

The preliminary results also reveal that such a reservoir would ensure continuous pipeline operation in drought periods lasting as long as 226 days. Clearly, in a realistic project, a smaller size reservoir would probably be selected for design purposes, in view of the generally accepted concepts of engineering-risk design, and the fact that the pipeline would normally not be operational per design for about 20 days per year for maintenance purposes.

At this stage, it would probably be impossible to decide which operation would be more feasible, from the hydrologic or economic points of view. However, the spectrum of possible solutions obtained for the various scenarios mentioned would be quite useful in the future, in that one or more of these options may turn out to be directly applicable to a coal slurry pipeline with a given capacity and origination point. Again a preliminary evaluation, in this respect, indicated that the capital and operation costs of a water intake/conveyance system and an offstream reservoir would not necessarily be substantial. For example, for a pipeline with a 10 million tons of annual capacity, a 20-mile supply line with a 5,000 acre-ft offstream reservoir would mean an additional cost of about 40 cents per ton of coal transported.

On the issue of water rights, which was again completely beyond the scope of this preliminary study, the following remarks are considered appropriate. Two significant problems will face the owner/operator of a coal slurry pipeline. First, under the riparian doctrine, the use of water may not be permitted for a coal slurry pipeline based on the traditional limitations to the land adjoining the stream or body of water from which it is taken. Second, even if such use is considered a riparian use, there is the obstacle of the principle that water must be shared with all other riparian users from the same source. It is conceivable, therefore, that the water rights issues would quite probably be resolved in court and decided upon the general principles of the riparian doctrine. However, through a realistic cooperation and responsive legislation in the long-standing integrity of the state control of state resources, implementation of statewide evaluations of the regional priorities may be compromised, particularly if the region is characterized by abundance of water. As is usually the case with any legal or institutional matter that is not covered clearly and in its entirety in the applicable law, the degree of complexities and difficulties may increase considerably. However, it is also because of these difficulties and costly delays encountered in certain specific cases, that the solutions to subsequent problems on similar matters may be achieved at an accelerated pace. The "first of its kind" development leading to the settlement of water rights matters for the ETSI pipeline could, therefore, constitute a very significant and enlightening example for future compromises in this respect.

ECONOMIC AND SOCIO-ECONOMIC CONSIDERATIONS

One of the main economic features of pipelines in general, and of coal slurry pipelines in particular, is that they are predominantly capital intensive, with up to 70 percent of the costs being fixed. The reverse is invariably the case with the railroads, where up to 80 percent of the costs may be variable, and thus strongly affected by inflation. It is clearly demonstrated by numerous detailed economic investigations, notably the ones concerning the ETSI and the Coalstream pipelines, that even if the current rates were the same for the coal slurry pipelines and railroads for comparable distances and capacities, the railroad rates would become about three times as high as the pipeline rates within the project life of a slurry pipeline, namely about 30 years, based on consistent estimates of the inflation scenario for "business as usual" conditions. Nevertheless, a final decision concerning the economic impacts of the development of a particular coal slurry pipeline must be based on a detailed analysis of various other economic and socio-economic factors, such as market stability, contractual conditions, supply potential, availability and terms of capital, impacts on other shippers, and employment.

Although the scope of this preliminary study does not include socio-economic impacts, the following remarks are offered on an entirely preliminary basis and primarily with reference to the findings of several other investigations on relevant issues. On the issue that pipelines would critically jeopardize railroad business, the ETSI study, as well as the more general study of the Office of Technolgy Assessment, concludes that railroads would transport no less coal after 1985, when the planned pipelines are considered to begin operation, than they are currently transporting. The primary reason behind this prediction is that the fraction of the market captured by the pipelines should be quite small, even without the increase that is projected for the overall amount of coal to be transported up to and beyond 1990. A recent study made for the Appalachian Regional Commission predicts that railroads would lose less than 8 percent of their projected coal transportation by 1990. In other words, the potential loss of revenues for the eastern railroads due to implementation of the planned coal slurry pipelines in Appalachia would be about 1.34 percent of the projected railroad revenues for 1990. This is clearly a minor effect. Nevertheless, it would conceivably imply some loss of employment opportunities with the railroads.

A detailed analysis of the temporary and permanent work force characteristics of coal slurry pipelines in Virginia was also beyond the scope of this preliminary investigation. However, for the sake of an entirely preliminary assessment, the work force predictions made for the ETSI pipeline can be employed as a basis. It is prescribed in the final report of the Environmental Impact Statement (EIS), that the construction will take two years to complete the first portion of the pipeline to transport 25 mty. The second phase will take an additional five years to augment the 1664-mile long pipeline to a capacity of 37.4 mty. The report estimates, that the first phase of the construction will require a total of 32,597 man-quarters of work force. Of this, 2,235 man-quarters are associated with the construction of three slurry preparation plants, 15,750 man-quarters with the main slurry pipeline, 8,390 with the 23 pumping stations, and 6,222 with the 9 dewatering plants. The total permanent work force for the operation of the pipeline, on the other hand, is calculated to be 753. Emphasizing the entirely preliminary nature of any similarities that may be considered, it can, nevertheless, be argued that a construction work force of about 10,000 man-quarters and a permanent work force of about 300 personnel would be required for a typical 400-mile long, 10-mty capacity coal slurry pipeline in Virginia. Clearly, these rather conservative figures contradict the counter arguments that the employment situation in Virginia would be adversely affected by the development of coal slurry pipelines. It should further be remarked that a very recent study by Bechtel Corporation projects that the seven coal slurry pipelines being considered would create about 46,000 jobs for construction, 4,765 direct employment jobs, and at least 100,000 indirect jobs in related manufacturing businesses and other supporting sectors.

In a statement by the American Association of Railroads (AAR), it was claimed that for every job opened for coal slurry pipelines, six jobs will be lost in the railroad business. This translates into a loss of 2,000 jobs in Virginia, according to the same statement. The methodology employed in these projections has never been made clear. It is likely, however, that these estimates are based on pre-Staggers Act conditions, and assume that all of the projected 75-mty haulage in Virginia will be captured by pipelines. More objective estimates clearly indicate much lower ratios, and find the AAR projections to be rather unfounded. Nevertheless, using the same methodology, an extremely high estimate would be that about 400 railroad jobs would be affected by a 10-mty slurry pipeline, which would in turn create at least 250 permanent jobs, and a substantial number of temporary construction job opportunities as well as many indirect employment in related supporting industry. It is also an interesting note, that according to a recent AAR yearbook, railroad employment across the country has dropped from the 1929 figure of 1,660,000 to 385,000 in 1981. One very obvious and significant reason, in this respect, must be the modernization and automation of the railroad systems. Since, in addition, only one slurry pipeline is currently in operation, such a dramatic drop in the past cannot be attributed to pipeline development.

It can further be argued, that since any pipeline development would be associated with demands of newly developed markets, the alleged loss of railroad jobs would affect only the future opportunities, and not the present work force. Therefore, the question is not whether an alternative mode of transportation will cause a reduction in the present work force of railroads, but as to whether future job opportunities of both temporary and permanent nature should be flatly denied to pipelines, in an economic system of free competition.

LEGISLATIVE CONSIDERATIONS

Although it is again, neither the intension, nor within the scope of the preliminary study referred to herein, a brief discussion is considered appropriate concerning the legislative aspects of coal slurry pipelines in Virginia, with particular reference to free market competition and eminent domain issues as stated in various authoritative publications, as well as recent developments and trends.

Currently, coal slurry pipelines require rights-of-way through numerous states for an interstate pipeline or within a given state for an intrastate pipeline. The rights-of-way to cross railroads, in particular, have been consistently denied in the past. And in Virginia, there is a law that denies the right of eminent domain specifically to coal slurry pipelines. It is because of this impasse, that a Federal eminent domain law is currently on the agenda in Washington. Based on the votings in the various committees and subcommittees, it appears quite likely that both the House and the Senate bills may become law this year. If the federal eminent domain law passes and Virginia continues to restrict coal transportation by pipelines, then an intrastate pipeline would not be feasible. An interstate pipeline starting in West Virginia or Kentucky would become inevitable, and most probably bypassing the coal sources of southwestern Virginia, unless such a pipeline is forced to pick up southwestern Virginia coal by means of an amendment in the Federal law. If such an interstate pipeline is built, Virginia coal would be even more significantly disadvantaged by a transportation rate differential, and thus would lose its domestic and overseas markets considerably, if not totally. If, on the other hand, Virginia decides to allow the construction of a coal slurry pipeline by way of a speedy legislative action, such a pipeline could provide a considerable price advantage for the high-quality Virginia coal over the neighboring states, in both domestic and export markets.

Finally, effective competition is undeniably the most essential element of the free market economics, and public policy should not be developed on the basis of protecting established interests by making market entry difficult or prohibitively expensive. Furthermore, in view of the flexibility contained in the Staggers Act, railroads now have the means of competing effectively with other transportation systems, including coal slurry pipelines. Consequently, there is probably no longer any valid grounds for the argument that railroads would be placed at an economic disadvantage if pipelines are allowed to be developed. Continued delay in building pipelines will only perpetuate the captive shipper dilemma for coal producers and ultimately works as a disincentive for expanded use and export of coal. A market test for coal slurry pipelines is, therefore, essential if there is the hope to achieve economic efficiency in coal transportation.

CONCLUSIONS

The current status of conventional coal slurry pipeline technology is at a very satisfactory level, including the environmental interaction related aspects. Various types of nonconventional slurries are also under investigation and some already in application stage, all with very promising features. These generally favorable characteristics appear to be definitely valid for an application in Virginia, as well. Motivated additionally by the current coal production and demand as well as transportation situations in Virginia, a preliminary yet realistic feasibility study was conducted at Virginia Tech. In addition to the overall favorable economic features, this study also revealed that there are no extraordinary technical or environmental problems associated with the conceived Virginia coal slurry pipelines. Both hydraulic transport and cost characteristics appear to indicate a general agreement with the previously reported trends. In view of the strong likelihood of the Federal eminent domain law, it appears that Virginia coal will be significantly disadvantaged, unless Virginia legislature expediently resolves the current situation regarding the restrictions for the construction of a coal slurry pipeline in Virginia.

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